# 3 Natural Gas Demand, Supply and Infrastructure

## 3.1 Summary Findings

This chapter examines issues regarding the demand and supply of natural gas for the San Diego region. The western United States, and especially California, are undergoing a tremendous increase in demand for natural gas as plans unfold to build several thousand megawatts of new natural gas-fired electric generating capacity.[1] This level of development raises questions about the ability of the region's gas delivery system to meet this new demand without adverse consequences for existing natural gas consumers.

There are three main areas in the analysis of natural gas issues for the region:

1. ***Supply/Demand*** of the commodity itself
2. ***Delivery/Capacity*** of the infrastructure that serves San Diego gas customers
3. ***Pricing*** of the commodity and its delivered cost to the customer.

The significant gas issues facing the San Diego region are prioritized in this summary within three time-periods, with the main area indicated. Depending on the end-use customer's perspective (or the utility's, or other market participant's), the overall importance of these summary findings will be different, e.g., core customers may consider long-term supply and price stability issues the most important for understandable reasons. The distinctions between residential and non-residential gas use, or "core and noncore use" of gas is where the most controversy has historically been in the three main areas analyzed. The simple fact is that it will continue to remain that way in the gas industry as long as these customers share this same commodity and same delivery system infrastructure. Within the long-term time frame of this study, the multitude of competing core/noncore gas interests are expected to remain in place.

### 3.1.1 Short-Term Findings (Now to 2006)

The most important findings that face the San Diego region in the short-term are:

- ***Supply/Demand*** **and** ***Delivery/Capacity*** **and** ***Pricing***—A significant challenge will be resolving and managing the disparate gas interests of two primary gas customer classes, namely residential (core) and non-residential (noncore, especially major Electric Generators). This issue has been in place since the unbundling of gas began more than 15 years ago in California. These issues will increase in the future due to capacity and supply constraints and increased cost pressures.
- ***Pricing***—Significant regulatory changes are currently underway as part of the implementation of the Gas Industry Restructuring (GIR) proceeding and delayed Biennial Cost Allocation Proceeding (BCAP) that will affect the manner in which gas transmission costs are set and services are provided by the gas utilities in southern California. Although temporarily delayed until 2003, potential BCAP issues such as a return to embedded-cost pricing, elimination of resource plans, required long-term (15-year) commitments by noncore customers, peaking tariffs, and incremental pricing for capacity expansions will most likely all be revisited and litigated. Adequate representation of San Diego gas customers is crucial to protect the interests of the region.
- ***Delivery/Capacity***—There is sufficient regional natural gas transmission and distribution capacity to serve core customers for the next 10 to 20 years.
- ***Delivery/Capacity***—The completion of the Baja Norte pipeline in Mexico within the year may help mitigate any capacity constraints on the SDG&E system. The degree to which this supply line will serve SDG&E gas load is uncertain.

[1] A total of 2,554 MW of new generation was added within the CAISO control area in 2001 and an additional 2,961 MW of generation is expected prior to June 2002. (CAISO 2002 Summer Assessment, Version 1.1, May 2002.)

- ***Supply/Demand***—Projected gas demand growth for electric generation (EG) is unclear, but may be as high as 60 percent of new gas growth. This also has significant implications on capacity and pricing.

### 3.1.2 Mid-Term Findings (2006–2010)

- ***Supply/Demand***—Expediting the re-powering or replacement of the two existing inefficient large generation plants in the region would increase the region's gas efficiency dramatically, possibly delaying the need for capacity expansions. The South Bay plant is scheduled to be replaced by a state-of-the-art plant by 2009, but there appears to be little incentive for the owners of the Cabrillo Power Plant to improve its efficiency. Additionally, there are many other opportunities to implement natural gas efficiency measures, including water heater insulation blankets, commercial boiler tune-ups and replacements, solar hot water heating in domestic and commercial hot water systems and pool heating.
- ***Supply/Demand***—The construction of LNG plants in Mexico will potentially come on line during this period and the extent that they will provide gas supply or other services to SDG&E and its customers is an important issue for the region.
- ***Delivery/Capacity***—Near the end of the decade, capacity adequacy is less certain, however, it appears that SDG&E is prepared to respond to the expanding needs of the distribution system in a manner that would prevent curtailments and provide firm service. Non-core users, however, will have to pick up much of investment risk in the future.

### 3.1.3 Long-Term Findings (Post 2010)

- ***Supply/Demand***—A significant risk in the long-term is adequacy of gas supply. Natural gas production in the United States will likely peak between 2015 and 2020 leaving a power generation infrastructure that is dependent on a declining national resource.
- ***Delivery/Capacity***—In the period between 2010 and 2015, SDG&E gas infrastructure expansion will most likely be necessary. Of the potential pipeline expansion projects SDG&E has evaluated, one in particular stands out as the most beneficial to the region, the Rainbow to Santee 30-inch pipeline. This project would significantly improve system reliability, especially in time of emergencies or when other transmission lines are in need of maintenance. It is currently estimated to cost $90 million to construct, however it would add as much as 170 million cubic-feet per day (MMcfd) to the capacity of the system, approximately a thirty percent increase in system capacity.

## 3.2 Natural Gas Demand, Supply and Prices

### 3.2.1 Natural Gas Consumption and Growth

Figure 3-1 shows the historical 5-year growth rates for natural gas demand for San Diego for 1981 through 2001.

### 3.2.2 Natural Gas Demand Forecast

For the 2002–2006 time period, natural gas demand is projected to grow by between 1.5 and 2.5 percent per year. Growth rates for the region (including Baja California) will be much higher due to the high growth in Baja California, which is expected to be as much as 9 percent per year for the next 9 years. Beyond 2006, average growth rates of natural gas are expected to be about 1.2 to 1.6 percent per year. Natural gas will grow from 1,439 million therms (MMtherms) in 2001 to 1,600 MMtherms in 2006, and to 2,032 MMtherms in 2030 as shown in Figure 3-2.

**Figure 3-1: Natural Gas Demand 5-Year Growth Rates**

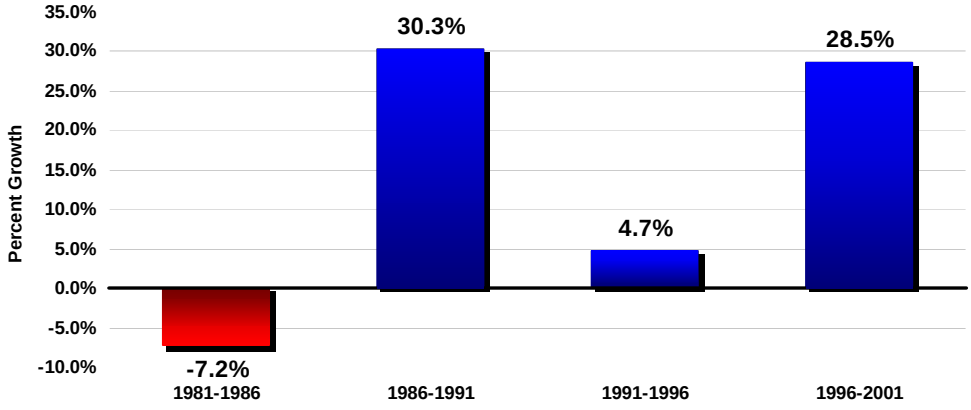
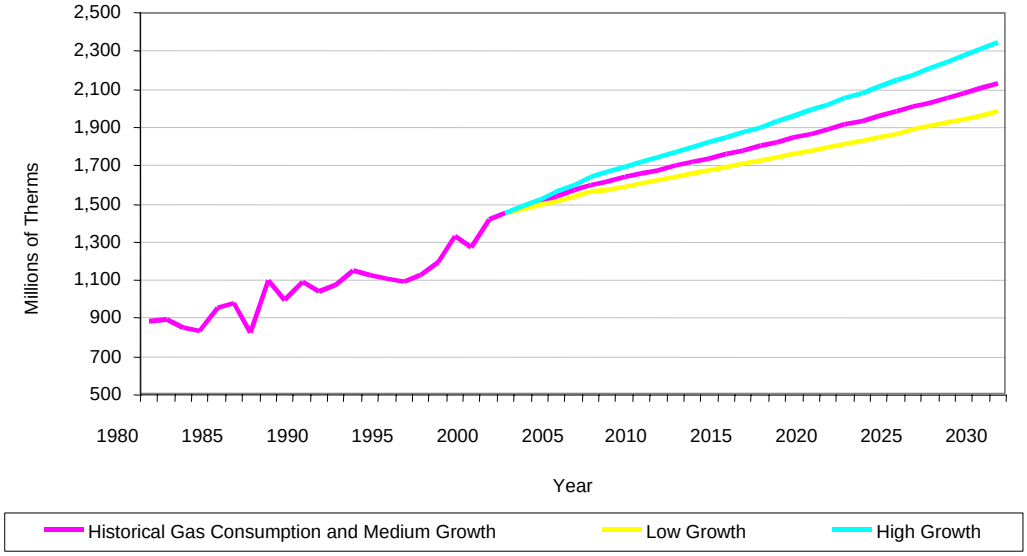



**Figure 3-2: Natural Gas Consumption**

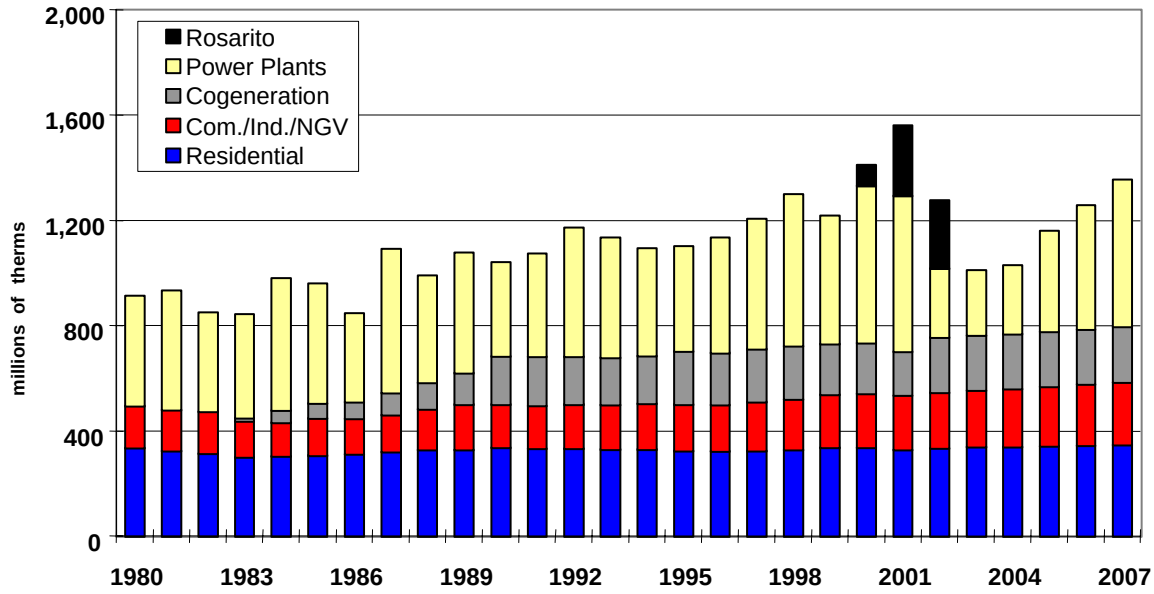



Source: SAIC scenarios based on SDG&E forecast to 2006 and CEC forecast to 2020, then extrapolated to 2030.

Natural gas historical and projected consumption by sector is illustrated in Figure 3-3, which clearly shows that a) electric generation is likely to experience the future growth and be the most variable; and b) there is minimal variability in residential and commercial demand and the overall growth rates are more modest. Figure 3-4, which represents the recent historical natural gas demand for utility and non-utility generators also illustrates the volatility and high growth that is a result of power plant development.

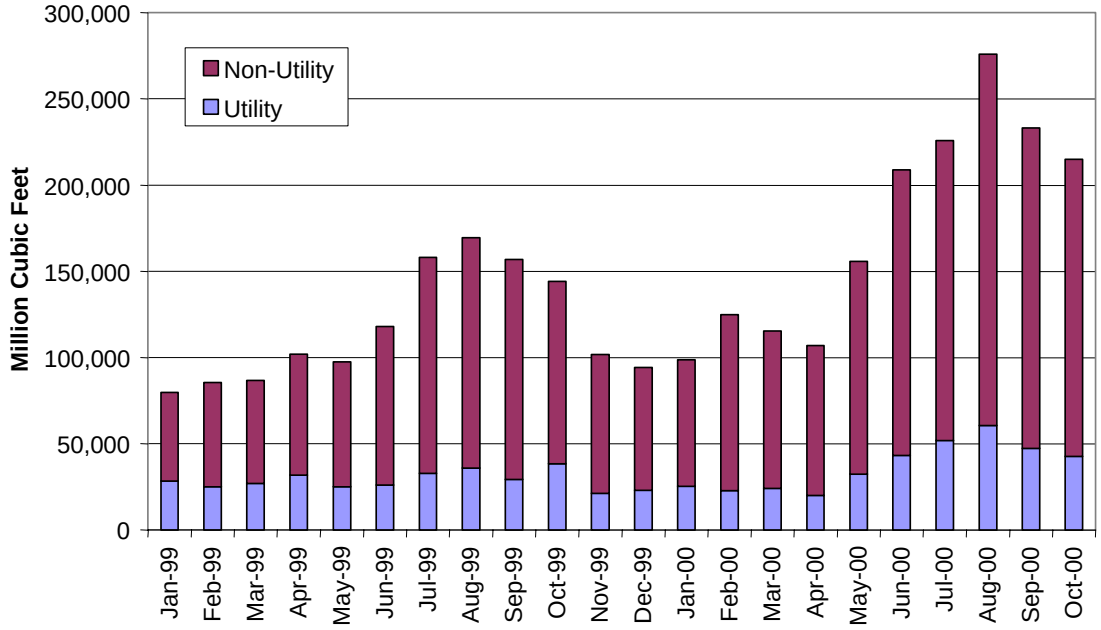
Appendix E presents the historical and forecast natural gas consumption by scenario. Growth rates used through 2006 are 1.5, 2.0, and 2.5 percent for the low, medium and high scenarios, respectively. For years 2007 and beyond, growth rates used are 1.0, 1.2, and 1.6 percent for the low, medium and high scenarios, respectively. The primary driver for gas demand in the near-term is business growth as a result of the recovery from the economic recession, longer-term growth is driven primarily by power plant demand. While new electric generation plants brought on-line during this period will significantly increase demand, older plants that are repowered could produce a net reduction in demand due to higher plant efficiencies. Another driver for growth is the anticipated increase in the use of natural gas for cogeneration.

**Figure 3-3: Natural Gas Consumption by Sector**




Source: SDG&E.

**Figure 3-4: Natural Gas Consumption for Electric Generation, WSCC**




Source: Energy Information Administration, Electric Power Monthly

While residential use of natural gas may grow at a modest rate of about 0.5 percent, commercial and industrial uses are projected to grow at a much higher rate of 2.0 to 5.0 percent per year.[2]

[2] The 5% growth rate is provided by SDG&E.

### 3.2.3 Natural Gas Prices

The California Public Utilities Commission (CPUC) regulates retail rates. Table 3-1 compares retail natural gas price increases by customer use. Residential customers pay the highest rates, followed by commercial and industrial customers.

**Table 3-1: Retail Natural Gas Price Estimates ($2002/MM Btu)***

| | | | | | Non-Core Industrial |
|---|---|---|---|---|---|
| 2000 | $9.66 | $9.01 | $7.07 | $5.92 | $5.92 |
| 2001 | $10.36 | $9.58 | $7.64 | $6.27 | $6.27 |
| 2002** | $9.33 | $8.59 | $6.76 | $5.46 | $5.46 |
| 2003 | N/A | N/A | N/A | N/A | N/A |
| 2002 | $6.81 | $6.08 | $4.25 | $3.04 | $3.04 |
| 2003 | $6.72 | $6.01 | $4.22 | $3.06 | $3.06 |
| 2004 | $6.48 | $5.81 | $4.14 | $3.06 | $3.06 |
| 2005 | $6.57 | $5.89 | $4.19 | $3.11 | $3.11 |
| 2006 | $6.44 | $5.79 | $4.16 | $3.13 | $3.13 |
| 2007 | $6.52 | $5.86 | $4.21 | $3.19 | $3.19 |
| 2008 | $6.61 | $5.94 | $4.26 | $3.25 | $3.25 |
| 2009 | $6.70 | $6.02 | $4.32 | $3.30 | $3.30 |
| 2010 | $6.55 | $5.89 | $4.27 | $3.31 | $3.31 |
| 2011 | $6.57 | $5.92 | $4.29 | $3.36 | $3.35 |
| 2012 | $6.67 | $6.01 | $4.35 | $3.42 | $3.41 |
| 2013 | $6.68 | $6.03 | $4.39 | $3.49 | $3.48 |
| 2014 | $6.74 | $6.09 | $4.45 | $3.55 | $3.54 |
| 2015 | $6.79 | $6.13 | $4.50 | $3.61 | $3.60 |
| 2016 | $6.79 | $6.15 | $4.54 | $3.65 | $3.65 |
| 2017 | $6.82 | $6.20 | $4.58 | $3.71 | $3.71 |
| 2018 | $6.87 | $6.23 | $4.62 | $3.78 | $3.77 |
| 2019 | $6.92 | $6.28 | $4.67 | $3.83 | $3.83 |

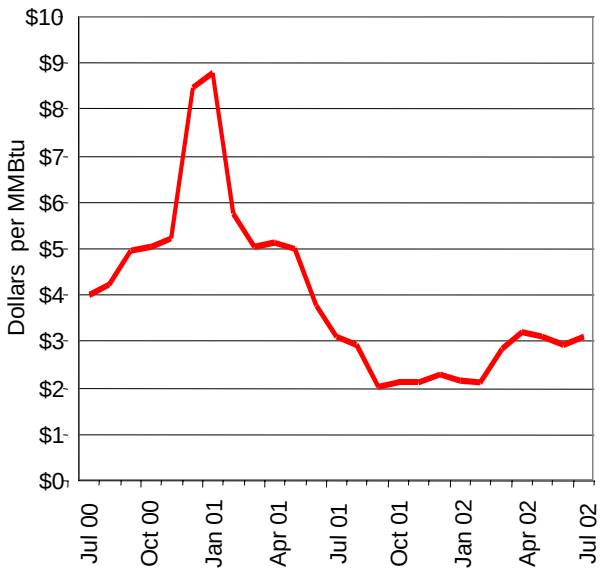
Source: SDG&E.
* 2003 price data not available for short-term forecast years. Only appears as long-term forecast.
** Source: CEC. Years 2000 to 2003 represent the short-term forecast and 2002 to 2019 represents the long-term price forecast.

Table 3-2 shows the various components and the sensitivities of the retail cost to price variations. These costs are for a typical electric generator in San Diego, core and other smaller customers pay much higher delivery costs on the two Sempra LDC systems. The data show that wellhead prices of natural gas and interstate pipeline charges are the two most expensive and volatile components of the natural gas supply chain.

Commodity gas prices are unregulated and in the long term are largely a function of national and international supply, which is a function of exploration, drilling and extraction. The amount of exploration and drilling is a function of price at the wellhead. Over the shorter term, commodity prices are a function of the relative level of storage, pipeline deliverability capacity, as well as weather effects. This relationship can be seen in Figures 3-5 and 3-6, which compare the Price of Natural Gas at the Permian Basin to Storage Levels over the same time period.

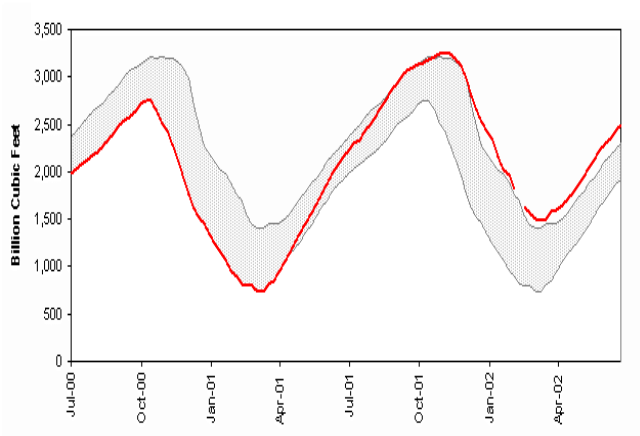
## Table 3-2: Natural Gas Cost Component Range and Variability Factors
(Typical Noncore Electric Generator Costs)

| | | | | Variability Factors |
|---|---|---|---|---|
| Supply Basin Wellhead Cost (Southwest USA) | $ 2.50 | –20 to +60 | $ 2.00 to $ 4.00 | Reserves/demand<br>Production rates<br>Drilling rig count |
| Interstate Pipeline Charges (Including third-party deliveries at Calififfornia border) | $ 0.30 | –50 to +10,000 | $ 0.15 to $ 30.00 | Total Capacity Demand |
| LDC Costs (Sempra Utilities) | | | | |
| Transmission | $ 0.10 | –10 to +100 | $ .09 to $ 0.20 | CPUC policies on cost allocation/rates<br>Market Power<br>EG demand growth |
| Storage/Balancing | $ 0.00 | +100 total | $ .00 to $ 0.20 | |
| Distribution/Customer Service | $ 0.05 | –20 to +200 | $ .04 to $ 0.15 | |
| Other | $ 0.05 | –20 to +300 | $ .04 to $ 0.20 | |
| Sub-Total | $ 0.20 | | $ .17 to $ 0.75 | |
| TOTAL Burner Tip Cost | $ 3.00 | –22% to +1060% | $ 2.33 to $ 34.75 | |




Source: California Energy Markets

## Figure 3-6: Natural Gas Storage Levels




Source: Energy Information Agency

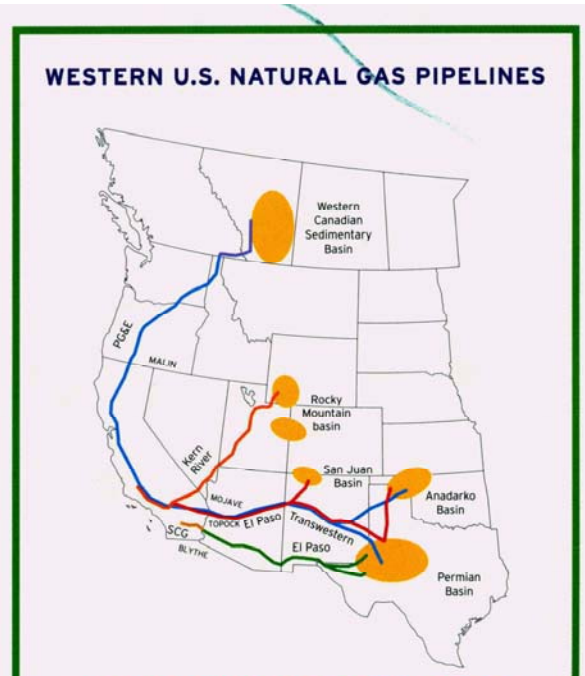
Recent low gas prices can be attributed to current high levels of storage. Industry reports indicate that storage will reach full capacity long before the historical beginning of withdrawal season that starts in early November. As of July 19, there was 2,486 Bcf of working gas in storage in the U.S., 334 Bcf higher than at the same time last year and 364 Bcf above the 5-year average of 2,122 Bcf.[3]

## 3.3 The Natural Gas Supply Chain

SDG&E, an investor-owned utility, is the local distribution company (LDC) for natural gas in San Diego County with a gas customer base of over 775,000 natural gas meters. SDG&E receives gas service from the Southern California Gas Company (SoCalGas) on a wholesale customer basis. SoCalGas is wholly-owned by Sempra Energy, the same holding company that owns SDG&E, and is the largest gas distribution company in the United States. SDG&E, as well as SoCalGas, import gas that is produced at several major supply basins from Texas to Canada. Gas is shipped to receipt points that interconnect with major interstate pipelines as shown in Figure 3-7. The well-known Topock receipt point, for example, near Needles, California, is the location where the Transwestern and El Paso pipelines deliver gas to SoCalGas. Topock is also the point where PG&E receives gas as the Mohave Interstate pipeline continues into California. The Wheeler Ridge receipt point, near Bakersfield, is where SDG&E has contracted for deliveries of Canadian gas to be received into the SoCalGas system.

All shippers, including local distribution companies, large industrial customers, and energy marketers, purchase capacity on the interstate pipelines to deliver gas from particular suppliers and receipt points on the system to particular delivery points. Shippers can elect to purchase firm capacity, which will be available under all but emergency circumstances, or non-firm capacity, which can be recalled at the discretion of the pipeline company to meet the needs of customers with firm capacity.

**Figure 3-7: San Diego Gas Supplies from Five Major Gas Basins**




PIPELINE DELIVERY CAPACITIES INTO CA

| | EXISTING FIRM CAPACITY (MMCF/D) | NEW FIRM CAPACITY (MMCF/D) |
|---|---|---|
| PG&E GT-MW | 1,850 | 354 |
| KERN RIVER | 835 | 903 |
| TRANSWESTERN | 1,090 | 150 |
| EL PASO | 3,290 | |
| QUESTAR | | 80 |
| TOTAL | 7,065 | 1,487 |

Source: Sempra Energy

A map of the SDG&E system is presented as Figure 3-8. Another map of the SDG&E with interconnections to major transmission lines can be found in Appendix E.

It is important to recognize that the San Diego region is geographically located at the very end of the transmission pipeline network that brings natural gas from the producing basins in North America. Although the San Diego region has access to all these basins by interstate pipeline access, the final delivery into the SDG&E system is dependent on just one pipelineSoCalGas. This provides market power to that pipeline and places the San Diego region in a tenuous position with regard to its natural

[3] Energy Information Agency (EIA) Weekly Natural Gas Storage - http://tonto.eia.doe.gov/oog/info/ngs/ngs.html

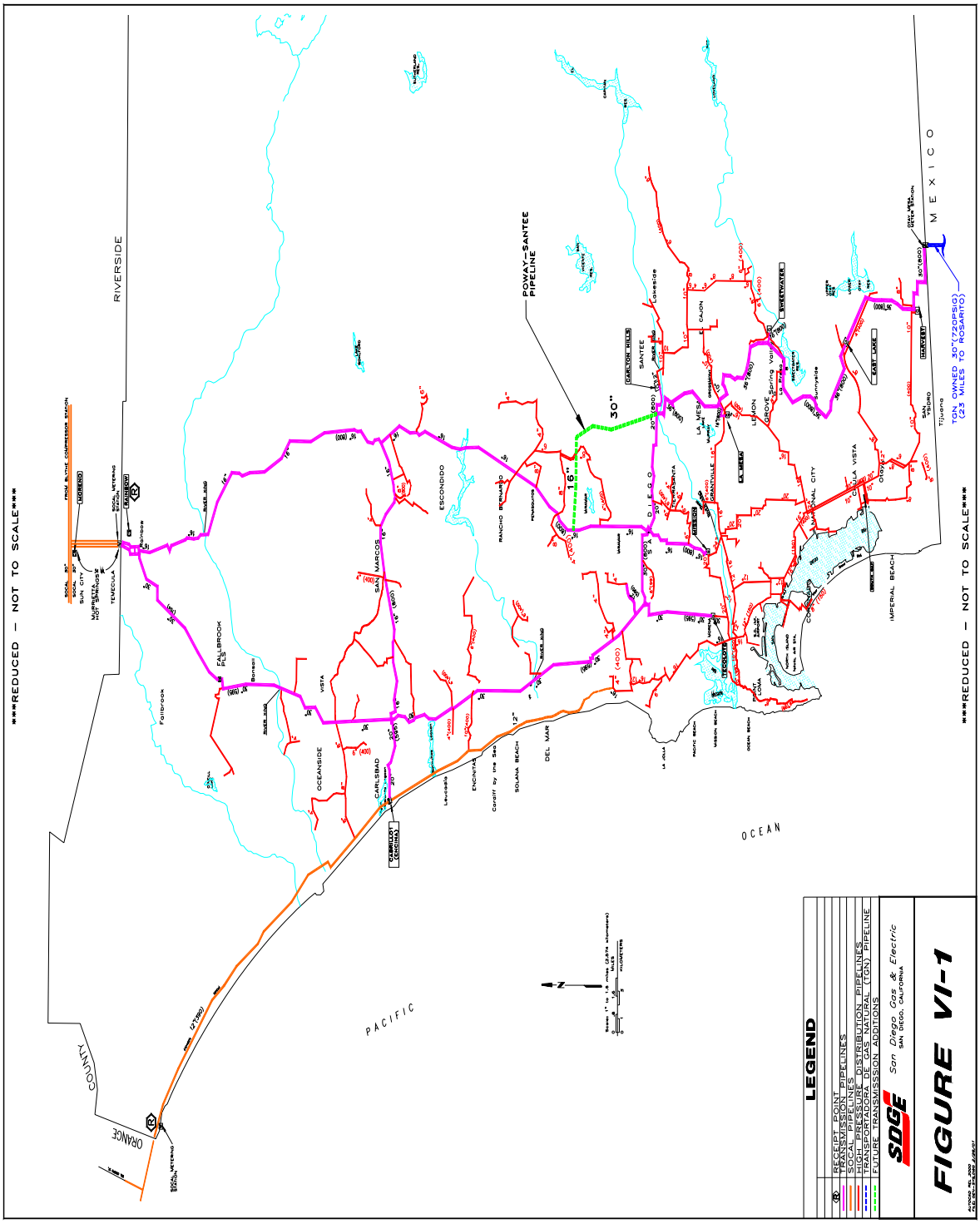



**Figure 3-8: Detailed Map of SDG&E Natural Gas Distribution System**

gas delivery options. For the first time in the region's energy history, however, potential access to other gas supply sources (LNG) and alternative delivery options (Baja Norte) are on the horizon and are therefore significant to the San Diego region (these projects and their implications are discussed in Chapter 3.6).

### 3.3.1 SoCalGas System Descriptions and Capacities

SoCalGas has an extensive pipeline network that has 3,875 MMcfd of firm receipt point capacity, including recently installed 375 MMcfd of capacity. An additional 200 MMcfd of interruptible capacity, along with 105 Bcf[4] of gas storage in four fields, brings the total system capability to deliver up to 6,000 MMcfd to SoCalGas customers. SoCalGas owns and operates four major underground gas storage fields in its service territory. There are no other gas storage providers in southern California.

The last major pipeline expansion on the SoCalGas system was the "Southern System Expansion," as it was called, and it was completed around 1990. It was a major expansion of the large, backbone transmission lines coming in from the Southwest receipt points.

### 3.3.2 SDG&E System Description and Capacities

The SDG&E gas system is capable of delivering 600 MMcfd in the summer and 620 MMcfd the winter on a firm basis. The difference in summer and winter capacities is due to factors such as gas temperature, engine operating conditions, customer load profiles, and customer load locations. These two operating capacities include a reserve margin of 45 MMcfd to account for various potential scenarios that could affect deliverability. Possible scenarios that could cause a reduction are lower Moreno suction pressure, Moreno or Rainbow compressor outages, or other system outages. The figure of 45 MMcfd assumes any one of these could occur on a peak day. It is possible that deliveries could exceed the 620 MMcfd under various conditions. Such a condition developed this past winter where the total SDG&E send-out was 639 MMcfd for 1 day in January.

For the purposes of determining available capacity to meet customer elections for core and noncore firm service, the 620 MMcfd Winter and 600 MMcfd Summer figures will be used. Obviously, there will be times when interruptible service will be available to noncore customers. SDG&E's interruptible customers have enjoyed a high level of service in spite of their interruptible status for many years due to SDG&E's use of APD planning criteria (see Section 3.4). Prior to November 2000, SDG&E's power plants had seen few curtailments in the past ten years. Most of these were in the winter months when core demand was highest and the resulting curtailment amounts were very insignificant. That was not the case in the late 1980s however, which preceded the installation of facilities required to meet growing core customer demand on both the SDG&E and SoCalGas systems.

The major pipeline facilities on the SDG&E system consist of a 30-inch diameter pipeline and a 16-inch diameter pipeline that extend south from the Rainbow meter station at the Riverside-San Diego county line. The 30-inch line veers west from Rainbow and continues south for about 50 miles to the Tecolote city-gate regulator station in Linda Vista. About 80% of the gas received at Rainbow is transported through this line. The-16 inch pipeline leaves Rainbow and heads due south again for about 50 miles and connects to the Mission city-gate regulator station.

These two local transmission pipelines are interconnected in two locations as they work their way south through the county. A 12-mile, 16-inch crosstie, half way down and again at the southern end a 4-mile, 30-inch pipeline connects them both. A 20-inch line connects at the southern crosstie and extends 7 miles to the Carlton Hills city-gate regulator station located in Santee. From Santee, a 36-inch line proceeds south about 30 miles to Otay Mesa at the southeast end of the SDG&E system. Four city-gate regulator stations feed high-pressure distribution networks from this line. Finally, a 4 mile, 30 inch line extends from the Harvest regulator station to the U.S./Mexico International border. These last few lines have been installed within the past 10 years.

[4] The firm withdrawal rate from storage is around 3,200 MMcfd, with a maximum withdraw rate that exceeds 3,600 MMcfd. 1,900 MMcfd of withdrawal capacity is reserved for core customers.

A 12-inch-diameter line, commonly known as the "Coastline" extends 43 miles south from the San Onofre metering station near that San Diego/Orange County lines and continues to La Jolla. This line is owned and maintained by SoCalGas. The pipeline is interconnected at four locations along its path. This pipeline was the original pipeline serving San Diego and is more than 50 years old. It operates at a much lower pressure (and volume) than the other transmission lines serving SDG&E customers.

SDG&E also owns and operates a major compressor station at Moreno Valley, situated 33 miles north of the San Diego County line. SDG&E installed this compressor station in SoCalGas' service territory to boost the pressure coming off of their major transmission line bringing in gas from the Southwestern gas basins. The Moreno station has increased its capacity over the years and now totals about 16,600 bhp. The Moreno station provides pressure to the SoCalGas lines 1027, 1028, and 6900 that comprise the Moreno-to-Rainbow transmission corridor. Line 6900 just last year completed the final phase of its 32-mile length, increasing the capacity into the SDG&E system by 70 MMcfd.

SDG&E's pipeline expansions over the last decade have included its "Pipeline 2000" project. This project was a major transmission project on the SDG&E system that enhanced its deliveries to the southern part of its service territory, including potentially Baja California.

The only other compressor station SDG&E owns and operates is on the SDG&E system itself, and is located at Rainbow in Northern San Diego County. This station has a capacity of 3,080 installed brake horsepower and is used to pressurize the 16-inch line leaving the Rainbow station.

### 3.3.3 Slack Capacity on the SDG&E and SoCalGas Systems

Slack capacity is defined as the amount of unused firm transmission capacity, typically on an annual basis, divided by the amount of firm transmission capacity. It is expressed in a percentage. It is important to note that slack factor is calculated using annual average figures, not peak day. Table 3-3 shows the slack capacity on the SDG&E and SoCalGas systems. SDG&E has a slack factor of approximately 50 percent for transmission capacity on its system under nearly every scenario. Note this forecast is only through the year 2006.

**Table 3-3: Slack Capacity Under Different Weather Scenarios Shows Adequate Backbone Transmission Capacity through 2006**

| | | SDG&E |
|---|---|---|
| Average Temperature, Normal Hydro | 37% | 49% |
| Average Temperature, Dry Hydro | 31% | 46% |
| Cold Temperature, Normal Hydro | 33% | 47% |
| Cold Temperature, Dry Hydro | 28% | 44% |
| Hot Temperature, Normal Hydro | 38% | 51% |
| Hot Temperature, Dry Hydro | 33% | 48% |

Note: CPUC Calculations Based on Utility Forecasts of Natural Gas Demand, August–October 2001

## 3.4 Gas Utility System Planning Criteria

SDG&E performs analyses on potential facility expansions in the context of their BCAP Resource Plans. Currently, planning is done to meet, at a minimum, the core peak day demand for a 1-in-35-Year Recurrence Interval for a design Abnormal Peak Day (APD) condition. This 1-in-35-year criteria provides an optimal design that meets the CPUC standards of least cost planning, while providing an acceptable level of service to core customers.[5] This APD condition is expected to occur once in every 35 years, or expressed in terms of probability, it has roughly a 3 percent chance of occurring in any

[5] SDG&E has noted that this level of service has historically provided an acceptable level of service to noncore customers as well.

given year. It represents an average daily temperature on the SDG&E system of 42 degrees, or a 23 heating degree day (HDD).

Recently, as part of a gas transmission Order Instituting Investigation (OII 00-11-002) filed with the CPUC, SDG&E has proposed a new approach in light of the difficult task of providing service for the anticipated growth in electric generation (EG) gas demand.[6] This new proposal for their planning criteria is known as Firm Service Demand, or FSD. The FSD includes both core and non-core demand on a 21 HDD day, and is also thought of as having a 10-percent chance of occurring in any given year. In their 2002 BCAP application, SDG&E provided an indicative projection of EG throughput for Firm Service Demand (FSD) planning.[7] This increased conservative planning criteria is in response to the growing uncertainty of EG customer firm service requirements. SDG&E's latest forecast of gas demand under this condition is shown in Table 3-4. As illustrated, the current system capacity is exceeded by demand in the year 2008. Without further capacity expansions, SDG&E will not be able to meet the FSD planning criteria in 2008. This FSD planning criteria proposal by SDG&E has not yet been approved by the CPUC.

**Table 3-4. SDG&E Firm Service Day (FSD) Demand**

**1 in 10 Year Recurrence Interval**

| | | | | **Total (MMcfd)** |
|---|---|---|---|---|
| 2003 | 380 | 63 | 37 | **480** |
| 2004 | 379 | 63 | 38 | **480** |
| 2005 | 379 | 63 | 67 | **509** |
| 2006 | 382 | 63 | 100 | **545** |
| 2007 | 387 | 63 | 136 | **586** |
| 2008* | 393 | 63 | 170 | **626** |
| 2009 | 400 | 63 | 174 | **637** |
| 2010 | 407 | 63 | 177 | **647** |
| 2011 | 414 | 63 | 181 | **658** |
| 2012 | 421 | 63 | 184 | **668** |
| 2013 | 427 | 63 | 188 | **678** |
| 2014 | 434 | 63 | 192 | **689** |
| 2015 | 440 | 63 | 196 | **699** |
| 2016 | 446 | 63 | 199 | **708** |
| 2017 | 452 | 64 | 203 | **719** |

*Available capacity is 600 MMcfd summer and 620 MMcfd winter on a firm basis.

The expansion of SDG&E gas transmission capacity is being addressed as part of the OII proceeding. During the winter of 2000–2001, SDG&E had to order gas curtailments of electric generators on its system. There were no curtailments during this past winter of 2001–2002, where even the CPUC predicted curtailments to occur on very cold days.[8]

### 3.4.1 Capacity Additions on the SDG&E System

At this point on the SDG&E system, any significant increases in gas demand will necessitate increases in pipeline system capacities. Any new significant incremental non-core demand, such as the proposed Otay Mesa Power Plant, may not have a utility firm service option without system

[6] This OII proceeding is discussed in further detail in Appendix E.
[7] SDG&E provides illustrated forecasts in some regulatory proceedings. SDG&E believes that large EG customers should provide SDG&E with their forecasted needs so that a system can be designed to meet their needs.
[8] California Public Utilities Commission, "California Natural Gas Infrastructure Outlook 2002-2006", November 2001, page 53.

expansion.[9] Available service options will vary depending on where the new load is located on the SDG&E system, e.g., new load on the northern end of the system can be accommodated more readily. Table 3-5 summarizes the potential facility expansions on the SDG&E system. Appendix E contains a more detailed description of these potential projects.

**Table 3-5: SDG&E Potential Facility Expansion Projects**

| Option | Facility - 50 MMcfd Options | Capacity (MMcfd) | Capital Cost ($MM) | O & M Cost ($MM/year) | In Service |
|---|---|---|---|---|---|
| 1 | Rainbow - Escondido Pipeline (23 miles) | 45 | $38 | Mimimal | 2 - 3 years |
| 2 | Rainbow - Fallbrook Pipeline (15 miles) | 50 | $29 | Minimal | 3 - 4 years |

| Option | Facility - 90 - 170 MMcfd Options | Capacity (MMcfd) | Capital Cost ($MM) | O & M Cost ($MM/year) | In Service |
|---|---|---|---|---|---|
| 1 | Rainbow - Escondido Pipeline (23 miles) | | $38 | Mimimal | 2 - 3 years |
| | Escondido - Santee Pipeline (26 miles) | | $52 | Minimal | 3 - 4 years |
| | Total: Rainbow o Santee Pipeline (49 miles) | 150 - 170 | $90 | Minimal | 3 - 4 years |
| 2 | Rainbow - Main Line Valve 7 Pipeline (25 miles) | | $47 | Mimimal | 3 - 4 years |
| | Miramar - Santee Pipeline (7.5 miles) | | $15 - $20 | Minimal | 3 - 4 years |
| | Total: Option 2 | 100 - 120 | $62 - $67 | Minimal | 3 - 4 years |
| 3 | Carlsbad Compressor Station (17,000 HP) | | $34 | $4 | 3 - 4 years |
| | Miramar - Santee Pipeline (7.5 miles) | | $15 - $20 | Minimal | 3 - 4 years |
| | Total: Option 3 | 90 - 100 | $49 - $54 | Minimal | 3 - 4 years |

Project #1 (90–170 MMcfd option) described in Table 3-5 is the most likely project to be constructed on the SDG&E system to meet increasing demand. The total length of this pipeline would be 49 miles, extending to the existing 36-inch Pipeline 2000 in Santee. Essentially, this pipeline would complete a loop between the Rainbow Compressor station and the southern extreme of the SDG&E service territory. SDG&E personnel confirmed this project is ideal to significantly improve system reliability, especially in time of emergencies or when other transmission lines are in need of maintenance. The lead-time for this project is estimated at three to four years, with the southern portion being the most problematic since it goes through federal government property and various sensitive environmental zones. The cost of this entire project would be about $90 million and add 150 to 170 MMcfd to system capacity. Similar to Line 6900, this line could be built in phases, or increments, as demand increases over time.

SDG&E notes that if demand growth warrants more capacity, all the identified projects can be increased in size to 36-inch pipe to achieve additional capacity with an added cost of about $500,000 per mile. They also note that the estimates of lead-time and costs have been done on a very preliminary basis. Customer location is of course another factor, such as a major power plant siting.

[9] For example, a new 500-MW combined cycle power plant, with a 6,000 Btu/Kwhr heat rate, can create a maximum daily gas burn of 70 MMcfd, which would be over a ten percent increase in SDG&E's capacity. As a comparison, the existing San Diego major power plants have heat rates of approximately 10,000 Btu/kwhr, much more inefficient due to their dated technology.

### 3.4.2 SoCalGas System Planning Criteria

SoCalGas recently stated their policy of maintaining a 15 to 20 percent excess backbone transmission capacity relative to best-estimate, normal weather forecasts. Any capacity expansions requested beyond the 20 percent will use incremental pricing based on long-term shipper commitments. Unlike SDG&E, SoCalGas is no longer required to submit Resource Plans in its BCAP proceedings. Natural gas transmission capacity can meet future demand on the SoCalGas system, although there are periods of high use. On an average daily basis there is sufficient capacity. However, there may be intermittent periods when capacity constraints may exist.

### 3.4.3 SoCalGas Capacity Additions

During the course of the SDG&E gas system investigation last year, SoCalGas announced they were proceeding with capacity expansions on their backbone transmission system totaling about 375 MMcfd, bringing the total take-away capacity to 3,875 MMcfd. This expansion has been installed. These capacity additions cost about $55 million, and it is anticipated SoCalGas will seek rolled-in rate treatment of these facilities. They have also proposed to increase storage capacity by about 14 Bcf.

## 3.5 Natural Gas Infrastructure Policy Issues – Who Should Plan and Pay for SDG&E Capacity Expansion?

A fundamental, and very controversial, pricing and resource economic issue is "Who is going to pay for any capacity expansions on the SDG&E system?" Just the annual facility costs that all customers pay on the SDG&E system alone are in the hundreds of millions of dollars,[10] and new expansion facilities will be expensive as well. Those interstate pipelines have historically required long-term contractual commitments to justify the building of such a pipeline. SDG&E signed such a contract in the early 1990s to bring about 50 MMcfd of Canadian gas down through the PGT Expansion project being built. That gas is not delivered directly into the SDG&E system, however, and is actually delivered into the SoCalGas system at Wheeler Ridge in the northern part of their service territory. Those contract costs (along with the cost of gas) have been passed through to the SDG&E customers that have seen the benefit of that supply, namely the core customers.

Historically, this question of who pays for expansion fell squarely on the utility itself. SDG&E would propose the least cost expansion plan to the CPUC, and if approved, SDG&E would build the necessary facilities and recover the costs according to CPUC adopted rate design. Now the responsibility is that of the CPUC.[11]

One important role of the CPUC was to question all aspects of these utility proposals, and decide whether to approve them or not. The forum in which this review was conducted was a General Rate Case (GRC). SDG&E has not had a GRC in nearly a decade (nor has SoCalGas for that matter). A GRC was an incredibly complicated, time-consuming proceeding that literally took years to file, litigate, brief, decide, and implement. It was extremely burdensome on the utility, the CPUC, and all other stakeholders in the process. Throughout the fifties and sixties many utilities, and SDG&E in particular, did not file a GRC: their rates in effect recovered all the facilities they had and any new ones being installed. Finally, SDG&E was forced to file a GRC in 1971, the first time in over a decade. During this time, facility costs were "rolled-in" to all customers' rates.

As the seventies progressed, OPEC prices and other inflationary forces began to skyrocket, GRCs became a regularly scheduled item on the CPUC agenda, at one point happening every year – for every utility in the state. During this time, with fuel prices at their most volatile level, the utilities were continuously evaluated on their purchasing practices through the proceedings, which were called "Reasonableness Reviews," which were oversight investigations that resulted in substantial disallowances of costs.

[10] SoCalGas allocates nearly one and a half billion dollars a year in annual fixed gas facility costs, including a portion to SDG&E.
[11] These matters are now addressed in the cost of service proceedings, which set rates and determines which customers should pay for expansion.

In the early 1990s, GRCs were eliminated with the advent of "Performance Based Ratemaking", or PBR. Basically, what the initial PBR did was freeze the utility rate base (with a small annual escalation) and the utility would have to use its productivity and any other means to live with that amount. They could not come back to the CPUC and ask for more money in the traditional GRC model. One quid-pro-quo, of course, was that Reasonableness Reviews were eliminated. In addition, for the first time ever for a gas utility in the state, SDG&E could actually make a profit selling gas. Prior to that time, all gas costs were simply passed through to the customer. The same situation was created on the electric side, which reaped profits as well with SDG&E owning two major power plants. As long as the customers were receiving safe and reliable service, with the customers' rates stabilized, the CPUC deferred from any micromanaging of the utilities infrastructure.

At the onset of PBR ratemaking, the CPUC did, however, promulgate a very clear policy toward any utility investment in gas infrastructure: <u>any facility investments made for noncore customers would be done so at 100% of the utility shareholder's risk.</u> With the significant infrastructure improvements made by SoCalGas and SDG&E during the seventies (which were placed into rate base) and especially late eighties, no real infrastructure improvements were necessary during the nineties, until recently.

SDG&E's and SoCalGas' current PBRs are scheduled to expire within the next year (this is one reason cited by the ORA for a delay in the 2002 BCAPs). It is anticipated that both utilities will petition the CPUC to extend their PBR ratemaking structure. Assuming that the PBR structure will continue in its basic form, the ratemaking treatment for capacity expansions will most likely continue to remain as it is today, i.e., noncore customers will be subject to incremental ratemaking treatment.

After this understanding of how utility gas infrastructure regulation is now operating, and the utility risks and rewards in that regard, the answer to who should fund, develop and build gas infrastructure in the region can be answered in two parts:

1. The core customer will continue to pay for facility expansions on the same basis as it does today by including in rates the costs of any facilities necessary to satisfy the CPUC adopted planning criteria of 1-in-35 year Abnormal Peak Day demand. This policy is discussed fully elsewhere in this report, but the general consensus is that additional facilities to meet this criteria are not needed on the SDG&E system for several decades. When the time comes, SDG&E would propose the least cost expansion plan to the CPUC, and if approved, SDG&E would build the necessary facilities and recover the costs according to CPUC adopted rate design.
2. For the noncore, it is an entirely different situation, especially due to their interruptible status. Expanding current utility gas infrastructure capacity will most likely be driven by actions of the noncore customers on the system. As explained above, under the current regulatory structure, the state's gas utilities have been more careful to invest in noncore gas infrastructure because of the cost recovery risk.[12] Third party gas infrastructure development may occur, but will be done at the risk of those developers, which typically does not occur without substantial commitment from shippers (most likely that same utility noncore customer). To date, the region's noncore customers have not been willing to make commitments necessary to expand gas infrastructure, whether utility or otherwise.

## 3.6 Other Regional Infrastructure Projects

### 3.6.1 The North Baja Pipeline Project

The 215-mile, $230 million North Baja Pipeline project (Baja Norte) is a joint effort of Sempra Energy, PG&E National Energy Group and Mexico's Próxima Gas, S.A. de C.V. It originates in Ehrenburg, Arizona, near Blythe, California, traveling south into Mexico just East of Mexicali as shown in Figure

[12] SoCalGas, report SDG&E in comments on the draft REIS, "has always been willing to build for non-core contractual commitments. SoCalGas seeks contractual commitments so that those wanting the additions pay for them, and not saddle all other customers with the cost. SDG&E made a proposal for system investments, which was voted on November 21, 2002.

3-9. The pipeline then continues west along northern Mexico to Rosarito in Baja California, Mexico. Just south of the U.S.-Mexico border from Otay Mesa, Baja Norte will link with the existing pipeline that receives gas from SDG&E for delivery to Rosarito. The proposed capacity of the line is 500 MMcfd and is expected to be in service by September 2002.

In May 2001, Mexico's Energy Regulatory Commission (CRE) issued Sempra Energy International a permit for construction of the 135-mile Mexico segment of the North Baja pipeline project. In October, PG&E National Energy Group (NEG) filed an application with FERC to build the 80-mile U.S. portion of the pipeline. In January this year, the FERC issued a certificate for construction and a Presidential permit authorizing the construction of the cross-border facilities.

**Figure 3-9: Map of the Baja Norte Pipeline**

(Source: PG&E National Energy Group)

The companies signed agreements for more than half of the pipeline's 500 MMcfd capacity and discussions are continuing with other potential customers. NEG will direct the permitting and development of the U.S. leg of the pipeline, while Sempra Energy International will direct the permitting and development of the Mexico leg. The initial design calls for a 36-inch line for the first 12 miles, a 30-inch line for the rest, and one compressor station in Arizona.

When the pipeline becomes operational, the gas SDG&E is currently providing to the Rosarito Beach power plant will be available to serve SDG&E customers. Currently, that load has averaged between 30 and 60 MMcfd. Relieving SDG&E of this capacity commitment will be a direct benefit to customers on the SDG&E system. The Baja Norte pipeline does not increase supply diversity by providing access to any new natural gas producing basins. Baja Norte will receive gas from the El Paso system in Arizona and redeliver it to Baja California, therefore, Baja Norte will compete for gas pipeline capacity serving California via the El Paso pipeline. During the summer of 2000, the El Paso system was fully utilized serving California, and when Baja Norte becomes operational, removing up to 500 MMcfd from the El Paso system could potentially have a serious impact on California deliveries.

Finally, the Otay Mesa plant being constructed in Chula Vista has submitted an application to build a pipeline directly to the Baja Norte pipeline in Mexico. This pipeline would have a capacity of 110 MMcfd. It has received a Presidential permit from the FERC in July 2001. It is scheduled for completion in September 2002, coincident with the Baja Norte completion date.

### 3.6.2 LNG (Liquified Natural Gas)

When natural gas prices soared last year, several companies said they were looking at plans to import LNG.

Table 3-6 summarizes the five LNG projects that have been announced recently for the Northern Baja Mexico Region. Naturally, not all projects will be built. Since each one has its own set of unique obstacles to overcome, it is too speculative to determine which ones might actually be built. What is clear is that the capacity output of these plants is higher than the gas supply needs within Northern Mexico, at least for the next couple of decades. This implies that gas supply from these LNG plants could potentially serve customers in California.

LNG is kept at ultra-cold temperatures, which liquefies the gas for transport aboard special tankers, primarily sea-born, however truck transport is also possible. It begins as natural gas in its usual vapor form. A process cools the gas to minus -259º Fahrenheit, changing the gas into a liquid that is less than 1/600th of its original volume.

**Table 3-6: Summary of Proposed Mexico LNG Facilities**

| | | | | | Remarks |
|---|---|---|---|---|---|
| Chevron Texaco | TBD | Australia | 500 MMcfd | 2006 | Waiting for other deals to collapse before proceeding |
| El Paso – Phillips | Rosarito | Australia Indonesia | 680 MMcfd | 2005 | Paid $16 MM for 74-acre plot, leasing adjacent lot. |
| Shell Gas and Power | Bajamar | Indonesia | 1,300 MMcfd – enough for 15 medium-size power plants. | | $500-million receiving terminal planned. Start in 2006. |
| Marathon Oil | Tijuana | Indonesia | 750 MMcfd | 2005 | Also 400 MW plant at site |
| Sempra – CMS | Bajamar (40 miles south) | Bolivia | 1,000 MMcfd | 2005 | Optioned 300 acres for $25 MM |

LNG has averaged a 9-percent growth in the world market in 1999–2000. The Petroleum Economist estimates that an average conservative growth of 10 percent per year is possible. However, if all facilities are built globally, a 52-percent increase in liquefaction will occur between 2002 and 2005. U.S. imports of LNG increased by 29 percent over the first 6 months of 2000. A sophisticated set of transportation and short-and long-term LNG contracting schemes are expected. The Petroleum Economist also noted that there has been a 30-percent reduction in the capital cost of liquefaction plants. Further supply chain improvements are estimated to actually lower the overall costs of LNG by 15 to 20 percent.

LNG has recently become a more viable source of future natural gas supply because of the vast extent of world natural gas resources and the significant decline in LNG costs in all segments of the supply chain. If sufficient domestic LNG processing capacity existed, LNG imports could potentially play an important role in the U.S. gas market by dampening natural gas price extremes. LNG could quite easily become the “swing” supply that would moderate price increases by increasing spot cargos of LNG during periods of high prices and conversely moderate price declines by reducing spot cargos during periods of low prices.

The EIA projects LNG costs of about $3.80 per Mcf, which is comparable to the recent high natural gas prices. The construction costs for re-gasification terminals, such as those proposed in Mexico, have also seem similar decreases. The LNG trade is very capital intensive due to the requirement of significant facilities at both ends of the supply route and tankers to transport over long distances. More than 70 percent of the cost of re-gasified, delivered natural gas is made up of processing and transportation costs.

There is considerable uncertainty about the cost of constructing new LNG terminals. The capital costs for any project are site-specific, and can vary considerably, depending on the harbor’s characteristics, land costs, access to interstate transmission systems, and the degree of local opposition to the project. As reported in a San Diego Union Tribune article (March 4, 2002), there are already parties fighting the plans for terminals being proposed in Mexico, ranging from environmentalists, preservationists, politicians and other public interest groups.

The delivered cost of LNG to a re-gasification terminal, such as those being proposed in Mexico, depends on the world LNG market. With that, there exists the potential for a few large LNG producers to create a cartel similar to OPEC. This situation, at a minimum, creates price uncertainty.

LNG does have the potential to insulate the region from supply disruptions. But only if that supply has been contracted for delivery to San Diego—for use in San Diego. There is a very real possibility that

scenario might not occur. The gas could stay in Mexico; it could also be transported through San Diego County for use elsewhere in California. Under one potential scenario, in order for LNG delivered to Baja California to get to markets north of San Diego County, the SDG&E system flow would need to be reversed. The feasibility of this potential requirement has not yet been studied.

Regardless, having additional gas supplies available in the region can help SDG&E's supply situation indirectly even if it is not contracted for delivery in San Diego. Additional supplies to other customers frees up supplies for San Diego.

### 3.6.3 Underground Natural Gas Storage

Natural gas storage is a means of insulating the region from gas supply disruptions. There are no on-system storage facilities on the SDG&E system, which is why SDG&E must size its transmission lines in order to meet peak day requirements. SDG&E contracts for all its storage needs from SoCalGas. SoCalGas is currently the only owner of storage facilities in southern California.

Traditional underground gas storage fields are not possible in the County due to the fact that there are no geological formations in which to develop such a facility.

At one point in the early 1980s, SDG&E owned and operated an LNG facility on its system for the purposes of providing gas storage. This plant was located at the southern portion of the South Bay Power Plant site in Chula Vista. The SDG&E LNG plant was eventually dismantled for various reasons, including the availability of more cost-effective storage services from SoCalGas.

SDG&E did have one other gas storage facility on its system, called the "Encanto holder," it was simply a series of large gas pipes buried underground that the company would pack and draft at certain times when needed. This storage was severely limited in its capacity, and was essentially rendered obsolete with other transmission system enhancements. It was dismantled in the mid-1990s.

## 3.7 Regulatory Proceedings and Issues

### 3.7.1 The Role of the CPUC

SDG&E and SoCalGas are jurisdictional local distribution companies (LDC) regulated by the CPUC. They are also known as "Hinshaw pipelines," which ensures that they will <u>not</u> be regulated by FERC. PG&E currently has the same status.

The CPUC sets the gas rates for SDG&E and SoCalGas. During the days of General Rate Cases, the Resource Plans were approved by the CPUC for the utilities to construct facilities necessary to meet the gas demands of their customers. As explained elsewhere in this report, GRCs are no longer conducted by the CPUC.

SoCalGas and SDG&E are currently in the midst of transitioning to a new gas ratemaking methodology. Since the beginning of regulatory control, the most common form of utility ratemaking was based on "embedded cost" determinations. In 1993, however, the CPUC adopted a form of "Long Run Marginal Cost" ratemaking, or LRMC.

LRMC ratemaking has now just about run its course. SoCalGas, in its next BCAP, will be transitioning its backbone transmission and storage system back to embedded cost ratemaking. The Gas Industry Restructuring (GIR) mandated this. In fact, most of the industry in California supported this return as well. PG&E's transmission system had gone back to embedded cost principles with its Gas Accord years ago, and it was only natural that SoCalGas would follow. SoCalGas, along with SDG&E, has taken this transition one step further and recommended in their 2002 BCAP (now delayed) filings a complete return to embedded cost ratemaking for all their costs. It is anticipated this issue will return in their 2003 BCAP filings.

A return to embedded cost ratemaking should eliminate many of the issues that have been occurring in LRMC proceedings and provide a higher level of rate stability to all gas customers, at least for their fixed costs. The transition may be difficult, however.

### 3.7.2 Core vs. Noncore Conflicts – What to Do

Customer classes have not always seen eye-to-eye in basic functions of gas supply, transmission, distribution, storage, and of course pricing of these components. Because all these functions are basically still heavily regulated by the CPUC and FERC (except the commodity price of gas at the wellhead), the resolution of competing interests is a major purpose for CPUC proceedings such as BCAPs. BCAPs set the gas cost allocation for all ratepayers, including SDG&E as a wholesale customer of SoCalGas. Fundamentally it is a "zero sum game", meaning that once the total revenue requirement of the utility has been set, the cost allocation methodology recovers those costs from all customers, with one customer class paying more if another pays less. Therein lies much of the controversy between customer classes in a BCAP proceeding.

Cost allocation of the utility's fixed costs is probably the most important issue in a BCAP that sets all customers' rates, but in recent years many other important policy issues have also been litigated in BCAPs. The managing of core interests is for the most part done by the LDC itself, such as SDG&E and SoCalGas, however this function continues to evolve and be influenced by organizations such as TURN and of course the Office of Ratepayer Advocates (ORA).[13] Noncore customers have become very active in both the resolution and management of gas issues, as is evidenced by the high level of activity by electric generators in this area, as well as wholesale customers and other noncore customer classes.

The core and noncore classes will continue to compete for supply, pipeline capacity, reduced cost allocations, and other favorable gas services. It is entirely possible that there is common ground between these two customer classes on issues, such as keeping delivery costs fair and equitable, supply reliable and safe, establishing a market structure that encourages competition and fair play by the utilities and other market participants, as well as others. When that opportunity presents itself, parties should work together to achieve those objectives. When it does not, each party should be well represented to serve its best interests.

Appendix E contains brief summaries of the current gas regulatory proceedings at the CPUC that are of interest to the San Diego region.

### 3.7.3 The Integration of SoCalGas and SDG&E Gas Operations

SDG&E and SoCalGas have a rather unique relationship at the moment. They are affiliate companies under the same corporate umbrella. The merger of these two companies occurred just a few years ago. As part of the condition of the merger, it was agreed that the two companies would continue to operate as separate gas utilities. However, recent regulatory proceedings since the merger have made attempts to take precedence over the merger agreement. For example, the two utilities proposed to merge their gas purchasing functions into one organization and combine the respective core portfolios in the Portfolio Consolidation proceeding (A.01-01-021). The final CPUC decision deferred the consolidation of the two core portfolios, until CPUC investigations are completed.

The future of the relationship between SDG&E and SoCalGas will continue to evolve, with the current path seemingly headed towards an eventual merging of the two gas companies completely. Whether this is good or bad for San Diego gas consumers remains to be seen.

### 3.7.4 The Peaking Tariff

The so-called "peaking tariff" on the SoCalGas system has been in place for the past seven years, and even though recently modified, the tariff has essentially operated as an "anti-bypass poison pill" for any customers contemplating alternative gas service.

In the utilities' defense of these peaking tariffs, their position is that customers that obtain service from other gas pipelines would end up using the utility gas system as a partial provider of gas services

[13] UCAN, the local San Diego consumer advocacy agency, has been very active in electric and telecommunication proceedings at the CPUC, and has been very effective in those areas. To date, they have not been as active on gas issues at the CPUC.

(presumably on a peak-only basis), leaving the captive customers subsidizing the partial bypass customers.

Since this peaking tariff has been in place, however, no alternative pipelines have been built in southern California. There has been no customer bypass of the SoCalGas system by any means: this tariff has never had a customer on it. The reason is the tariff would essentially have the customer pay for gas service twice: once to the alternate provider, and once again to SoCalGas (keeping the utility "whole" for any lost revenues). The result has been that gas pipeline competition has been kept out of southern California.

Now, however, with the Baja Norte pipeline nearing completion, there exists for the first time ever a potential bypass of gas service provided by SDG&E. Now the same situation could apply to SDG&E's own customers. Explicitly pointing to the construction of the Baja Norte pipeline, SDG&E proposed in its 2002 BCAP that it also have a peaking tariff implemented on its system (this 2002 BCAP proceeding has been delayed until 2003, and whether SDG&E will pursue this proposal in that proceeding remains to be seen). Until this regulatory hurdle is overcome, gas supplies from Mexico may not be economically feasible for San Diego.[14]

## 3.8 Important Implications and Considerations for the Region

Due to the extreme uncertainty of future growth of demand to support high growth of regional electric generation plants and longer-term dwindling supply, the region needs to continue to investigate and analyze opportunities for upstream diversification and delivery of natural gas supply, particularly deliveries directly into San Diego County. While the Baja Norte pipeline may help, it is limited to accessing supply from the Permian and San Juan basins only, and not larger supplies in the Rockies and Canada.

Additional issues and considerations include the following:

- There will be significant opportunities for the region to engage in the policy and decision-making process at the CPUC and CEC to evaluate and comment on capacity expansions for the SDG&E system in order to balance the gas demand needs and costs for all gas customers in San Diego against the regulatory, political, and environmental issues that facilitate or hinder gas infrastructure expansions.
- The region should strongly encourage the re-powering of two existing EG facilities to achieve higher natural gas efficiencies. Re-powering those two plants alone could significantly delay any gas system expansion projects required for existing gas customers. The capacity "freed up" could potentially be enough to completely absorb at least one other new power plant gas requirements.
- Currently, EGs in both SDG&E's and SoCalGas' service territories are served under the Sempra-wide EG rate tariff. This proposal was vigorously opposed by EGs in the SoCalGas service area because they opposed paying a subsidy to reduce the transportation rate to EGs in SDG&E. One result of this new rate design is that EGs in SDG&E's area now have the same rate as Los Angeles power plants, rather than a much higher cost. This makes generation in San Diego cost competitive, and without it, these local plants would have a hard time competing for electric sales. If this CPUC policy changes, it could place these plants at sufficient risk.
- The integration of SDG&E into the SoCalGas system has advantages and disadvantages. Improved performance in productivity, performance based incentives and other observable management practices need to be made transparent to demonstrate the benefits from such actions. However, greater oversight is needed on proposed rate increases.

[14] It should be noted that SDG&E's opinion in commenting on the draft REIS is that the peaking tariff does not address supplies from Mexico. It has no effect on gas supplies delivered at the California border to the SDG&E system. Study sponsors were asked to compare the costs on Baja Norte with the SoCalGas system.

- The potential for rapid development of LNG facilities and the potential of these facilities to serve San Diego County will present significant opportunities and challenges for the region. The region should closely monitor the progress of the proposed pipelines and LNG facilities and the potential of these facilities to serve San Diego County directly, including participating in any state or federal forums that set policy in this determination. If domestic supplies of natural gas start declining as expected in the next 15 years, LNG may be one of the few or only options available for additional supplies of natural gas.
- The region should implement programs or other means to conserve gas usage by all customers and investigate federal, state, and local funding to facilitate such programs.
- The potential for simultaneous price spikes in electricity and natural gas markets suggests that ownership of gas-fired resources alone may not provide much of a price hedge. The region should consider other resources such as renewables and energy efficiency.