Business Research Project

Analyzing the impact of Natural Gas Flow and Utilization on the regulated & unregulated Financials of Tennessee

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Executive Summary

The purpose of this research based project was to perform a comprehensive analysis of the leading natural gas utilities of US with the intention to demonstrate a meaningful and sustainable causal relationship between variables vital towards the financial operations of a utility firm. Emphasis was placed on demand side factors and their detailed long lasting effects on the financial performance of a corporation. A major contribution of the research conducted is to remove the irregularities due to unpredictable weather and the resulting implications over the financial results of the companies operating in the provision of natural gas to end users. Therefore this research was conducted by going over and above the basic financial measures popular to investors and financial analyst. It is intended that this work will assist both corporate and individual investors while evaluating decisions regarding investments in natural gas providers throughout the US.

Acknowledgement

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Industry Operations

Natural gas is a colorless, odorless fuel composed primarily of methane and ethane. It burns more cleanly than many other fossil fuels—emitting less carbon dioxide than coal or oil, and little sulfur or particulates—making it one of the most popular sources of energy today. The Energy Information Administration (EIA) estimates that natural gas consumption will rise from 27% in 2013 to between 32% and 33% by 2040.

The Natural Gas Supply Chain

The natural gas supply chain comprises three distinct segments: upstream, midstream, and downstream. The gas utilities are downstream.

Local distribution companies (LDCs) occupy the downstream segment of the gas industry, taking gas from interstate pipelines and distributing it to a broad range of customers, including residential, commercial, industrial, and power generation. They perform this service under a monopoly concession and are subject to rate regulation.

Companies sometimes run LDCs as stand-alone operations, but independent LDCs have become increasingly rare in recent years. Following regulatory reforms that eased restrictions on mergers by gas and other utilities, most LDCs are now owned by larger holding companies that also own other businesses, including other regulated gas and electric utilities, as well as unregulated businesses that may or may not be related to energy.

It is important to remember that LDCs perform two related, but distinct, services: the delivery of gas, as well as the procurement and sale of gas to the customer. LDCs deliver gas to customers through pipeline networks they build and maintain, and attempt to earn a profit for providing that service. In addition, they procure gas and sell it to customers at cost, a service for which they earn no profit. In both cases, state officials regulate the rates that LDCs can charge, and they have no guarantee that state regulators will allow them to recover fully the cost of gas sold to customers.

Alternatives to Cost-Of-Service Ratemaking

Cost-of-service ratemaking has several important disadvantages when it comes to the incentives it offers for efficient utility performance. Just determining the actual cost of service is a cumbersome, time-consuming, adversarial and complicated process due to the fact that many investor-owned utilities operate more than one LDC—thus raising issues about what costs should be allocated to what operation.

Furthermore, cost-of-service ratemaking offers a strong incentive for a utility to inflate the size of its asset base by so-called gold plating: overinvesting in assets that are either unnecessarily expensive or redundant, because the larger the rate base, the higher the return.

To counter this problem, some states have begun to experiment with incentive-based rates that seek to promote efficiency. These rates either offer rewards for the attainment of performance goals or punishments for the failure to achieve expected standards. Various kinds of performance-based structures exist, each with its unique set of advantages and disadvantages.

Regulatory lag. One of the simplest ways to create more incentives for improved performance is known as “regulatory lag,” it is the extension of the minimum time between rate changes. This produces a strong incentive towards cutting down costs, because utilities will keep 100% of any cost savings made during the period; they also would bear 100% of any additional costs incurred.

Price cap. Another kind of incentive-based ratemaking formula is the price cap, in which the charge for distribution is set through a formula that adjusts the previous charge according to inflation (usually based on the consumer price index) and also according to expected gains in productivity. This has the effect of forcing a utility to make productivity gains—because prices have already been calculated to reflect them. However, further gains would add to the utility’s return, providing a strong incentive to increase productivity beyond the set target. The success of this formula is dependent on correct setting of the expected productivity gain factor in determining future prices. If the factor is set too low, it would allow the utility to earn above-normal profits, on the other hand, setting a factor set too high might hinder its full costs recovery. Price caps are more common outside the US.

Revenue cap. An alternative to the price cap is the revenue cap, which can take the form of either an absolute revenue cap or a revenue-per-customer cap. With revenues fixed, companies can increase profits only by cutting costs.

Earnings sharing. Another kind of incentive-based rate that has gained popularity in recent years is “earnings sharing.” When regulators determine a utility’s rate of return for a given period, the specified return is actually a target return that the rate schedule is designed to produce.

Because actual events may lead to a different return, regulators may designate an “allowed rate of return” band that includes an acceptable variation from the target. If actual returns turn out to fall below that band, the utility may be allowed to petition for a rate change. If returns are above the target band, companies share the “excess” earnings, in part or in whole, with customers in the form of future rebates.

This protects the utility from unexpectedly low returns and allows customers to benefit from improved efficiency.

Each of these alternatives has potential drawbacks, and studies examining alternative regulatory regimes have found it difficult to determine their overall effects. Because incentive-based rate designs do not offer a clear opportunity to enhance returns and usually entail some risk, some utilities prefer to remain under traditional regulation.

Weather Influences Earnings

With delivery rates typically tied to the volume of gas delivered, and costs that are mostly fixed, LDCs' earnings traditionally have been highly sensitive to changes in the weather. Colder-than normal winter weather has the effect of increasing volume (and therefore, sales), while warmer than-normal weather can cut volumes significantly, eroding profitability.

In setting rates, regulators assume a particular level of demand and gas distribution volumes. Unusual weather patterns can make this assumption either too high, leaving the utility with a revenue shortfall, or too low, giving the utility a revenue windfall. To smooth these peaks and valleys, many states have now started to include "weather normalization" clauses that serve to reduce weather-related effects and redress earnings volatility. A shift in weather patterns that causes a greater- or less-than-expected number of degree days (a measure of the variation of the mean daily temperature from a reference temperature) triggers a surcharge (in the case of unusually warm weather) or credit (when the weather is cold), applied to customer bills in order to offset the effect of weather. A more recent option for utilities that are seeking to minimize the effects of weather on earnings is to use weather-based financial derivatives.

Because revenues are tied to delivered volumes, LDCs have a strong incentive to discourage energy efficiency and conservation, something state regulators would like to change as natural gas prices rise. In recent years in some states, a new "conservation tariff" has been used that decouples an LDC's revenue from its delivery volumes by protecting profit margins in the event that delivery volumes decline. This is accomplished by setting up mechanisms that change the price of gas delivered according to actual volumes delivered, or by "deferral accounts" that keep track of the impact of conservation measures and provide for deferred collections or refunds at set times.

Managing Gas Supply

In addition to maintaining a pipeline network, an LDC has responsibility to manage the supply of gas moving through its network, in order to maintain adequate pressure in the system and meet the full requirements of customers during times of peak demand. LDCs are responsible for delivering gas that customers have purchased from an independent competitive supplier, as well as supplying gas to customers that are either unable to choose a competitive supplier or fail to do so. When supplying gas directly to customers, an LDC has to purchase the gas itself, and it also has to pay for transportation of the gas to the LDC's network (and possibly for storage as well).

Deregulation Creates Choices

Before 1984, when deregulation of the interstate pipeline industry first began, LDCs were forced to buy their gas directly from the transmission pipeline company that served their area as part of a package that included both the gas itself and pipeline transportation to the LDC's city gate. LDCs made these purchases under long-term contracts that obliged them to pay for a certain amount of gas even if the LDC did not need the gas.

In 1984, Order 380 of the Federal Energy Regulatory Commission (FERC) freed LDCs of those "take-or-pay" contractual obligations, thereby allowing them to start buying gas directly from producers on the spot market, once their take-or-pay obligations were satisfied. The FERC went on to issue a series of orders dismantling pipeline regulations. This process culminated in 1992 with Order 636, known as "The Restructuring Rule," which required pipelines to offer transportation service as a separate service on terms equal to those given customers buying gas from the pipeline.

Since that time, a wholesale market for natural gas has developed in the US that allows LDCs to purchase gas on a variety of terms and from a variety of different sources. A new class of independent gas marketer sprang up to compete with gas producers and pipelines by offering different products that allow LDCs to create their own supply portfolios, reflecting the individual circumstances and needs of each LDC. LDCs have taken advantage of the shift to diversify their sources of supply away from pipeline companies; now they source a significant amount of their supply either directly from a producer, a producer's marketing affiliate, or from an independent marketer.

According to an American Gas Association (AGA) survey of its members on hedging practices in the winter of 2012–2013, about 84% of the gas utilities used financial instruments to hedge at least a part of their gas supply. More than half of the states now allow the practice of using tools, such as futures contracts and weather risk insurance, to stabilize natural gas prices.

Supply Contract Options

LDCs use a number of different kinds of contractual arrangements to purchase natural gas, the terms of these contracts can have a significant impact on the ultimate cost of the gas that the customers pay. LDCs can enter supply contracts for different durations: long-term contracts, which stretch for a year or longer, mid-term contracts, covering more than a month but less than a year, or monthly or even daily periods. For their peak-month supplies, LDCs tend to rely primarily on mid-term contracts (one to 12 months), though more than half of the respondents to the AGA survey reported using long-term contracts for as much as 50% of their peak-month supply.

In addition to differing timeframes, gas supply contracts can include one of several different pricing mechanisms, including a fixed price for the contract's duration, a weekly average price, a daily price, a first-of-the-month index, a three-day average, or the price of futures contracts traded on the New York Mercantile Exchange (NYMEX). As shown by the AGA survey, 20 of 22 LDC survey respondents used first-of-the-month pricing for their long-term contracts, and only a few used other pricing mechanisms. For mid-term contracts, first-of-the-month pricing was still the most common, though LDCs also used fixed, daily, and NYMEX-based pricing mechanisms.

In addition to their physical supply contracts, LDCs often will use financial derivatives to hedge the cost of gas for their customers. These financial instruments—futures, options, and swaps—are available through an organized, regulated exchange (such as NYMEX), as well as in the "over-the-counter" market, from trading desks at various commercial banks, investment banks, marketers, and other natural gas intermediaries.

The type of regulatory regime under which an LDC operates often has a heavy influence on purchases of the LDC's supply, and whether or not it uses financial futures to hedge risk. LDCs have to convince regulators that their gas purchases were prudent and reasonable, or the commission may not grant full reimbursement to the LDC.

Recovering Gas Supply Costs

LDCs supply natural gas to customers who have not arranged to buy gas from an independent marketer. Although recovering the cost of gas appears simple enough in theory, in practice it can be quite complicated. Gas prices fluctuate from day to day and from month to month, whereas rates may be set for years into the future. This timing mismatch creates a risk that utilities might not be able to fully recover the cost of gas purchased if what they collect for gas supplied is insufficient to cover their costs. Even more worrisome is the fact that regulators may not allow utilities to collect the full cost of gas if their initial cost estimates prove unreliable.

States make use of widely varying procedures in place for LDCs to recover the cost of gas they supply to customers. Some have automatic pass-through mechanisms linking customer prices to gas price indices that change prices monthly. However, in other states, LDCs must wait until the season is over and then they apply to regulators to recoup undercharges. They then run the risk that regulators are not going to permit full recovery of their gas procurement costs in the next rate case. During times of high gas prices, even delayed recovery of gas supply costs can hurt an LDC’s liquidity, which forcies it to increase its borrowings (thus raising its interest expense); in extreme cases, this can hurt its credit rating.

Transportation

Due to the physical properties of natural gas, it is difficult to transport by any means except a dedicated pipeline. While a few LDCs have their own gas production that can be used to supply customers, long-distance pipelines are the only realistic way for most LDCs to secure enough supply to cater to full customer demand. Until the mid-1980s, LDCs purchased their gas directly from the transmission pipeline serving their area, paying a single price for the gas along with any additional amounts charged for transportation and storage.

This arrangement worked well in assuring stability of supply but it was inefficient, as it required LDCs to contract enough gas to meet their peak demand levels throughout the year, even if the pipeline capacity went unused. LDCs passed these costs along to gas customers. The regulatory reforms that began in 1984 and finished in 1992 allowed LDCs to shop around for their gas from producers, instead of forcing LDCs to buy from pipeline companies.

The reforms also permitted LDCs to sell unused pipeline transportation capacity to others in what is termed as a “capacity release market.” As a result, LDCs now use a range of options to meet their transportation requirements, these include gas released from storage, short-term firm transportation rights, interruptible transportation, released capacity, and “gray market” services (capacity repackaged with supply or other services by LDCs or independent marketers).

Long-term contracts are preferred by gas firms for most of their natural gas supplies in order to ensure uninterrupted consumer supply, according to an October 2015 report of the Department of Energy (DOE), which assessed heating fuels and electricity markets.

Storage

Natural gas is bulky and expensive to transport. Gas storage facilities play an important role in LDCs' efforts to secure supply because it is not possible for pipelines to increase transportation capacity to large demand centers on short notice. In particular, storage is most important when demand exceeds pipeline transmission capacity that is during times of peak demand. According to the AGA, about 20% of the gas that is used during winter months comes from storage, while 50% or more of the gas burned on an extremely cold day may come from storage. It is for these reasons that gas storage facilities have become extremely important to LDCs. Gas can be stored in one of several types of facilities, including salt caverns, disused mines, aquifers, hard rock caverns, or depleted gas reservoirs. LNG also can be stored in specially constructed insulated containers near regasification terminals. Small volumes of compressed gas can be stored in tanks commonly referred to as gas holders. LDCs use such storage facilities for shipments to or from areas where pipelines are not available.

Owning or controlling storage reservoirs allows LDCs to guarantee future deliveries and to manage inventories actively against fluctuating natural gas prices. Control or ownership also reduces the reliance on transmission pipeline capacity and limits the potential effect of a pipeline outage. Owners can manage inventory by purchasing gas during times of weak demand, when prices are low, and storing it for use during periods of peak consumption. Storage owners can also lease capacity to third parties, providing an additional source of revenue. Because US natural gas consumption peaks in the winter, producers store gas during the months when temperatures and demand are moderate (April through October) and withdraw gas during the heating season (November through March). The US government, commodity traders, and LDCs track storage levels extremely closely to determine demand levels, supply availability, and likely future price trends.

INDUSTRY TRENDS

Operating Environment

It is essential for the gas utilities industry to obtain natural gas in order to provide for its varied end-use markets. As a result, any movement in natural gas prices that are somewhat volatile in nature can have an effect on gas utilities' profitability.Due to a substantial increase in supply, prices for US-based natural gas have been under strong pressure in the recent years. Historically, the industry was US-centric to a certain degree, but two key developments in recent years have rendered it more global in nature. First of which is the advent of liquefied natural gas (LNG), this is a promising prospect of transforming the US natural gas industry into an export market, which therefore has a dual potential, that is to access foreign demand as well as impact gas prices domestically. Secondly, many countries are increasingly moving toward cleaner-burning fuels that is either because of environmental preference or because of sudden shocks (*e.g.*, Japan's nuclear power capabilities being damaged after earthquakes). Hence, analysis of global LNG developments can resonate for natural gas markets at home.

The rapid growth in US gas supply is largely due to the shale revolution, which is directly via shale gas, and indirectly via shale oil plays that bring associated gas with them. In 2015, natural gas production in the US averaged 78.8 billion cubic feet per day (bcf/d) of marketed production, up from 74.9 bcf/d in 2014, according to the US Energy Information Administration (EIA). The EIA also forecast that production would reach 79.6 bcf/d in 2016 and 81.4 bcf/d in 2017. This represents 1.0% projected production growth in 2016 (due to low natural gas prices and a slowdown in rig activity), and 2.3% projected growth in 2017 (due to anticipated increases in prices and exports).

The three-year production compound annual growth rate (CAGR) implicit in the 2017 estimate, versus 2014 actual, is 2.8% per year. While a rise in total consumption of natural gas is also expected, demand growth pales in comparison. Looking at the same comparison of 2017 versus 2014, US natural gas demand is expected to increase a mere 2.1% per year, less than the implied CAGR on the supply side. According to EIA forecasts, demand growth is going to originate mainly from increases in the electric power sector's natural gas consumption. In terms of natural gas exports, the EIA expects increased demand from Mexico's growing electric power sector. LNG exports are expected to increase at an average of 0.5 bcf/d in 2016.

With supply surpassing demand, it comes as little surprise that the EIA also projects prices to be lower for natural gas in the coming years. In 2013, Henry Hub spot prices averaged $3.73 per million British thermal unit (MMBtu), rising to $4.39/MMBtu in 2014. Bentek Energy, a unit of Platts, notes that the winter of 2013–2014 was the fourth-coldest winter in 60 years, which explains some of the year-over-year gain in realized spot prices, in S&P Global Market Intelligence's view. However, the average spot price dropped to $2.63 MMBtu in 2015, due to lower demand as a result of warmer-than-normal temperatures in the winter of 2015–2016, record inventory levels, and production growth. The EIA sees spot prices averaging $2.22/MMBtu in 2016 and $2.96/MMBtu in 2017.

In S&P Global Market Intelligence's view, gas utilities should benefit from subdued natural gas costs, as this is likely to encourage more fuel switching, mainly from coal power plants to natural gas, hence increasing throughput on utility systems. We also see retail customer conversions from oil, electric, and propane heating to natural gas heating in many northern regions.

Overbuilding, Oversupply in the LNG Market?

The secular drivers favoring rise of natural gas demand, with potential for further gains from fuel switching, have also steered expansion of liquefied natural gas (LNG) markets. Previously a development only in Asia and Europe, many former US regasification plants have been converted to liquefaction plants, this enables them to participate in the LNG markets by harnessing cheap US based natural gas, to ship it overseas, and sell it into gas-needy markets in Asia or Europe.

Meanwhile, even without US participation until recently, LNG trade has shown a rapid growth. As noted by the EIA, Global LNG trade grew an average of 6% per year between 2005 and 2014. According to the International Gas Union, the global trade in LNG reached an all-time high of 244.8 million tonnes, or roughly 34.8 bcf/d in the year 2015, which represents 44.2% of US marketed gas production.

GAS DEVELOPMENT PROJECTS FOR LNG*

(arranged by estimated construction cost, year in service, in $, billions)

PROJECT NAME	PIPELINE	YEAR IN SERVICE	CAPACITY (Bcf)†	DEVELOPMENT STATUS	ESTIMATED CONSTRUCTION COST
Alaska LNG Project (Export Facility)	BP, Exxon Mobil, ConocoPhillips	2025	2.55	Announced	65.0
Lake Charles (Export Facility)	Lake Charles LNG	2020	2.20	Early Development	12.0
Cameron Parish - G2 LNG (Export Facility)	G2 LNG	2019	1.84	Early Development	11.0
Prince Rupert Island - Pacific NorthWest LNG (Export Facility)	Indian Oil Corporation, China Petrochemical, Progress Energy, Japex Montney, Brunei National Petroleum	2019	2.74	Early Development	11.0
Hackberry - Cameron LNG (Export Facility)	Sempra Energy, Mitsubishi, Mitsui & Co., Engie	2018	1.70	Construction Begun	10.0
Sabine Pass - Golden Pass LNG (Export Facility)	Exxon Mobil, Qatar Petroleum	2019	2.10	Early Development	10.0
Prince Rupert Island LNG (Export Facility)	BG Group	2020	2.91	Early Development	10.0
Cameron Parish - SCT&E (Export Facility)	SCT&E LNG	2021	1.60	Announced	9.4
Pascagoula - Gulf LNG (Export Facility)	Southern LNG, Lightfoot Capital Partners, Thunderbird Resources Equity	2019	1.50	Announced	8.0
Brownsville LNG - Rio Grande (Export Facility)	NextDecade	2020	3.60	Announced	8.0
Pelican Island LNG (Export Facility)	NextDecade	2021	0.77	Announced	7.7
Goldboro LNG (Export Facility)	Pieridae Energy Canada	2019	1.40	Early Development	7.6
Coos Bay - Jordan Cove Energy Project (Export Facility)	Veresen	2019	0.90	Early Development	7.0
Énergie Saguenay LNG (Export Facility)	GNL Québec	2021	1.60	Early Development	6.2
Kitimat LNG Terminal (Export Facility)	Woodside Petroleum, Chevron Canada	-	1.28	Advanced Development	4.5
Bear Head LNG (Export Facility)	LNG	2019	0.50	Announced	4.0
Saint John - Canaport (Export Facility)	Repsol	2020	0.67	Announced	4.0
Cove Point (Export Facility)	Dominion Cove Point LNG	2017	0.82	Construction Begun	3.8
Lake Charles - Magnolia LNG (Export Facility)	Magnolia LNG	2018	1.07	Early Development	3.5
Melford LNG (Export Facility)	H-Energy	2020	1.80	Announced	3.0
Brownsville - Annova (Export Facility)	Annova LNG	2021	0.94	Announced	3.0
Elba Liquefaction Project (Export Facility)	Southern LNG, Shell US Gas & Power	2017	0.35	Early Development	2.1
Calcasieu Parish - Live Oak LNG (Export Facility)	Parallax Energy	2019	0.64	Announced	2.0
Squamish - Woodfibre LNG Project (Export Facility)	Woodfibre Natural Gas	2017	0.29	Early Development	1.6
Main Pass Energy Hub	Freeport-McMoRan Energy	-	1.00	Advanced Development	1.0
Douglas Channel LNG (Export Facility)	AltaGas, EDF Trading, Idemitsu Kosan, Exmar	2018	0.23	Advanced Development	0.5
Delta - Tilbury LNG (Export Facility)	FortisBC, WesPac	2016	0.40	Construction Begun	0.4

Note: SNL guarantees coverage on natural gas pipeline projects longer than 10 miles, storage projects over 0.1 Bcf and LNG terminals filed with FERC and that are over 0.1 Bcf. SNL does not comprehensively cover projects below this threshold. *LNG - Liquefied Natural Gas, Project Type - Facility. †Bcf - Billion Cubic Feet.
Sources: S&P Global Market Intelligence; SNL Financial.

GAS DEVELOPMENT PROJECTS FOR LNG*
(arranged by estimated construction cost, year in service, in $, billions ... continued)

PROJECT NAME	PIPELINE	YEAR IN SERVICE	CAPACITY (Bcf)†	DEVELOPMENT STATUS	ESTIMATED CONSTRUCTION COST
Sabine Pass Liquefaction Project -Trains 1 & 2 (Export Facility)	Cheniere Energy	2016	1.38	Construction Begun	-
Cameron Parish - Waller Point LNG (Export Facility)	Waller Marine	2017	0.16	Announced	-
Port Arthur - WesPac (Export Facility)	Alturas	2017	0.20	Announced	-
Prince Rupert- Triton LNG (Export Facility)	AltaGas, Idemitsu Canada	2017	0.32	Early Development	-
Sabine Pass Liquefaction Project -Trains 3 & 4 (Export Facility)	Cheniere Energy	2017	1.38	Construction Begun	-
Stewart (Export Facility)	Canada Stewart Energy Group	2017	4.10	Announced	-
Cameron Parish LNG - Gasfin (Export Facility)	Gasfin	2018	0.20	Announced	-
Corpus Christi (Export Facility)	Cheniere Energy	2018	2.14	Construction Begun	-
Freeport LNG Liquefaction Terminal (Export Facility)	Freeport LNG Investments, ZHA FLNG Purchaser, Texas LNG Holdings, Turbo LNG	2018	1.80	Construction Begun	-
Jacksonville Project (Export Facility)	Eagle LNG	2018	0.07	Announced	-
Kitsault Energy (Export Facility)	Kitsault Energy	2018	2.70	Announced	-
Plaquemines Parish (Export Facility)	Louisiana LNG	2018	0.30	Announced	-
Brownsville - Texas LNG (Export Facility)	Texas LNG	2019	0.54	Announced	-
Cameron Parish - Calcasieu Pass (Export Facility)	Venture Global Partners	2019	1.41	Early Development	-
Hackberry- Cameron LNG Expansion Project (Export Facility)	Sempra Energy, Mitsubishi, Mitsui & Co., Engie	2019	1.41	Early Development	-
Prince Rupert Island - Orca LNG (Export Facility)	Orca LNG	2019	3.20	Advanced Development	-
Sabine Pass Liquefaction Project -Trains 5 & 6 (Export Facility)	Cheniere Energy	2019	1.40	Construction Begun	-
Delfin LNG (Export Facility)	Delfin LNG	2020	1.80	Announced	-
Freeport LNG Train 4 Expansion (Export Facility)	Freeport LNG Investments, ZHA FLNG Purchaser, Texas LNG Holdings, Turbo LNG	2020	0.72	Announced	-
Kitimat LNG (Export Facility)	Shell Canada, Mitsubishi, PetroChina, Korea Gas	2020	3.23	Advanced Development	-
Oregon LNG (Export Facility)	LNG Development Company	2020	1.25	Early Development	-
Plaquemines Parish - CE FLNG Project (Export Facility)	Cambridge Energy	2020	1.07	Early Development	-
Plaquemines Parish - Venture Global (Export Facility)	Venture Global Partners	2020	2.80	Announced	-
Brownsville - Gulf Coast LNG (Export Facility)	Gulf Coast LNG Export	2021	2.80	Announced	-
Port Arthur LNG (Export Facility)	Sempra Energy	2021	1.40	Announced	-
Prince Rupert - Aurora LNG (Export facility)	INPEX, Nexen Energy, Raritan Township	2021	3.12	Announced	-
Prince Rupert Island - WCC LNG (Export Facility)	Exxon Mobil, Imperial Oil	2021	4.00	Early Development	-
Stage 3 - Corpus Christi (Export Facility)	Cheniere Energy	2021	1.40	Announced	-
Sarita -Steelhead LNG (Export Facility)	Steelhead LNG, Huu-ay-aht First Nations	2022	0.11	Announced	-
Acushnet LNG Expansion	Eversource Energy	-	6.80	Announced	-
Bienville LNG	TORP Terminal LP	-	1.40	Advanced Development	-
Brownsville LNG - Eos/Barca (Export Facility)	Barca LNG, EOS LNG	-	3.20	Announced	-
Corpus Christi	Cheniere Energy	-	0.40	Advanced Development	-
Main Pass Energy Hub (Export Facility)	Freeport-McMoRan Energy	-	3.22	Announced	-
Oregon LNG Project	LNG Development Company	-	0.50	Early Development	-
Port of Tampa (Export Facility)	Strom	-	1.20	Announced	-

Note: SNL guarantees coverage on natural gas pipeline projects longer than 10 miles, storage projects over 0.1 Bcf and LNG terminals filed with FERC and that are over 0.1 Bcf. SNL does not comprehensively cover projects below this threshold. *LNG - Liquefied Natural Gas, Project Type - Facility. †Bcf - Billion Cubic Feet.
Sources: S&P Global Market Intelligence; SNL Financial.

According to market research firm SNL Financial, there are currently 61 LNG terminal projects in the US that are either announced or ongoing, including Sempra Energy's expansion of its Cameron LNG plant in Hackberry, Louisiana.

In October 2014, the facility started building its $10 billion, three-train liquefaction plant having capability to produce about 10.0 million metric tons per year. In February 2015, Sempra submitted a proposal for federal approval for expansion of the export terminal into a five-train plant with capability to produce a whopping 24.9 million metric tons per year. The Federal Energy Regulatory Commission (FERC) approved the proposal in May 2016, anticipating that Cameron LNG will become the largest export plant in the US.

Another large, ongoing LNG export terminal construction slated to come onstream in 2019 is Cheniere Energy's conversion of its Sabine Pass natural gas plant into an $18 billion worth liquefaction facility. The company is already liquefying some of its natural gas supply and exported its first batch of LNG in February 2016, via a tanker headed for Brazil, marking the US' entry in the global LNG trade market. Since then, LNG exports from that plant have reached Asia and Europe. Other significant LNG export terminal projects include Cove Point in Maryland, its completion expected is in 2017, and Port Arthur in Texas, where startup is targeted for 2021.

The EIA warned that in the advent of US LNG exports, the large amounts of incoming new LNG supply could potentially lead to excess global supply in the near term. Analysts from McKinsey & Co.'s Energy Insights unit stated in June 2016 that LNG supply is likely to exceed demand until 2024, adding that peak oversupply is expected by 2019. The analysts also said that the long list of ongoing projects for new liquefaction facilities might take long before being completed, given the supply situation.

Given these capacity growth numbers, S&P Global Market Intelligence does not expect that all projects on the drawing board will break ground. Some US-based LNG export facilities are likely to be built, and early movers are more likely, all else being equal, to succeed. At the end of the day, we think price spreads between US gas hubs and those in Europe and Asia will begin to compress, where differences would largely reflect transportation costs. As a result, we do not expect much in the way of foreign natural gas demand siphoning off US-sourced natural gas, and therefore not much impact on US natural gas prices in the next few years.

The Mechanics of Moving Gas

Natural gas is a colorless, odorless fuel composed primarily of methane and, to a lesser extent, ethane. It burns more cleanly than many other fossil fuels—emitting less carbon dioxide than coal or oil, and little sulfur or particulates— which makes it one of the most popular sources of energy today.

How do you bring a colorless, odorless fuel to the market? Companies typically move raw gas from underground reservoirs through a series of feeder (gas-gathering) pipes to processing plants which remove impurities and natural gas liquids (NGLs—such as propane or butane). The propane and butane can be stored and sold on site or moved through NGL pipelines to other locations. Processing plants then send the almost pure methane gas to long-distance transmission pipelines, resulting in what is also known as "pipeline gas." In some cases, the gas withdrawn from the ground is considered pipeline gas and can be moved directly from gas-gathering pipes into pipelines without the need to be processed.

The midstream segment comprises interstate pipeline, or "transmission," companies, which build and operate pipelines for the purpose of transporting gas from producing regions to demand centers. The FERC, which has jurisdiction over interstate commerce in natural gas, regulates transmission companies. As per the EIA estimates, there were 217,306 miles of interstate pipelines in the Lower 48 states at the end of 2008 (latest available) and an additional 88,648 miles of intrastate pipelines.

There is a flurry of investments in new and expanding pipeline networks. Currently, there are 82 natural gas pipeline projects (either announced or ongoing), according to SNL. Each of these projects is longer than 10 miles and has projected storage of more than 0.1 bcf. Among the largest in the US (based on estimated construction cost) are the Atlantic Coast Pipeline/Southeast Reliability Project, to be completed in 2018 (West Virginia –North Carolina, $51.0 billion); the Rover Pipeline Project, to be completed in 2017 (Pennsylvania/West Virginia–Michigan, $44.0 billion); the Mountain Valley Pipeline, to be completed in 2018 (Virginia–West Virginia, $35.0 billion); the Sabal Trail, to be completed in 2017 (Alabama–Florida, $30.0 billion); the Nexus Pipeline, to be completed in 2017 (Ohio–Michigan, $20.0 billion); and the Pacific Connector Gas Pipeline, to be completed in 2018 (Oregon, $18.0 billion).

Attached to the pipeline systems are many natural gas storage facilities, which store gas during periods of nonpeak demand to be able to maintain supply during peak demand times. There were nearly 400 active storage facilities as of November 2015 (latest available). As of March 2016, total storage capacity is 9.2 trillion cubic feet (tcf), and total working gas capacity, defined as the total gas minus base gas capacity, is 4.8 tcf. Base gas capacity is the amount of gas needed to maintain adequate pressure in a storage reservoir during the withdraw season.

GAS DEVELOPMENT PROJECTS FOR NATURAL GAS PIPELINES

(arranged by estimated construction cost, year in service, in $, billions)

PROJECT NAME	PIPELINE	YEAR IN SERVICE	CAPACITY (Dth)*	MILEAGE	DEVELOPMENT STATUS	ESTIMATED CONSTRUCTION COST
Mackenzie Valley Pipeline Project	Exxon Mobil, Imperial Oil, Shell Canada, ConocoPhillips, Aboriginal Pipeline Group	-	1,168,452	743.2	Postponed	164.0
Atlantic Coast Pipeline/Southeast Reliability Project	AGL Resources, Piedmont Natural Gas, Duke Energy, Dominion Energy	2018	1,460,565	550.0	Early Development	51.0
Prince Rupert Gas Transmission Project	TransCanada	2020	3,505,355	559.0	Advanced Development	50.0
Coastal GasLink Pipeline	TransCanada	2019	2,921,130	415.0	Early Development	48.0
Rover Pipeline Project	ET Rover Pipeline Company	2017	3,164,557	711.0	Early Development	44.0
Mountain Valley Pipeline	NextEra Energy, EQT, WGL Holdings, Vega Energy Partners	2018	1,947,420	300.0	Early Development	35.0
Sur de Texas - Tuxpan (Marino) Gas Pipeline	Comision Federal de Electricid	2018	2,531,646	497.0	Announced	31.0
Sabal Trail	NextEra Energy, Duke Energy, Spectra Energy	2017	830,000	500.0	Early Development	30.0
Nexus Pipeline	DTE Energy, Enbridge, Spectra Energy Partners	2017	1,460,565	250.0	Announced	20.0
Merrick Mainline Pipeline Project	Nova Gas Transmission	2020	1,927,945	161.0	Announced	19.0
Pacific Connector Gas Pipeline	Williams, PG&E, Veresen	2018	1,000,000	230.0	Advanced Development	18.0
Leach XPress	Columbia Pipeline Group	2017	1,460,565	160.0	Early Development	17.5
Nueces - Brownsville Pipeline	Comision Federal de Electricid	2018	2,531,646	150.0	Announced	15.5
PennEast Pipeline	AGL Resources, New Jersey Resources, South Jersey Industries, PSEG Power, Spectra Energy Partners, UGI Energy Services	2017	973,710	113.8	Early Development	10.0
Commonwealth Pipeline	WGL Holdings, UGI Energy Services, Crestwood	-	800,000	120.0	Postponed	10.0
Diamond East Project	Transcontinental Gas Pipe Line	2018	973,710	50.0	Announced	8.0
Coastal Bend	Gulf South Pipeline	2018	1,382,688	65.0	Early Development	7.2
Constitution Pipeline Project	Cabot Oil & Gas, Piedmont Natural Gas, Williams Partners, Capitol Energy Ventures	2016	650,000	124.0	Advanced Development	6.8
Leidy Southeast Expansion Pipeline	Transcontinental Gas Pipe Line	2015	511,198	30.0	Construction Begun	6.5
WBI/Dakota Pipeline	WBI Energy Transmission	-	389,484	375.0	Postponed	6.5
Florida Southeast Connection (Southern Pipeline Project)	NextEra Energy	2017	973,710	126.0	Early Development	5.4
Utica Shale Gathering	Gulfport Energy, Rice Energy	2021	1,800,000	165.0	Announced	5.2
Utica Shale Upgrade	Regency Energy Partners, American Energy Partners	2015	3,407,984	52.0	Announced	5.0
Dominion Supply Header	Dominion Resources Inc.	2018	1,460,565	39.0	Early Development	5.0
Roadrunner Gas Transmission	ONEOK Partners LP, Fermaca Infrastructure	2019	623,174	205.0	Advanced Development	5.0
Dalton Expansion Project	Williams, AGL Resources	2017	436,222	111.2	Early Development	4.7
Northern Access 2016 Project	National Fuel Gas Supply, Empire Pipeline	2016	497,000	97.0	Early Development	4.5
NGTL Extension	TransCanada PipeLines	2018	2,629,017	55.0	Early Development	4.3
Utica Gathering System	Summit Midstream Partners	-	778,968	115.0	Advanced Development	4.0
Great Basin Energy Project	Genova Energy Link, Rooney Engineering, LK Energy	2024	243,427	125.0	Postponed	3.4
Cameron Access	Columbia Gulf Transmission	2018	778,968	34.0	Early Development	3.1
Ohio Valley Connector	Equitrans	2016	1,168,452	35.5	Early Development	3.0
Cameron Pipeline Expansion Project	Cameron Interstate Pipeline	2016	2,268,744	21.0	Construction Begun	2.9
MARC II Pipeline	Central New York Oil & Gas Company	2017	973,710	31.0	Announced	2.5
Leismer to Kettle River Crossover Pipeline	NOVA Gas Transmission	-	946,446	46.0	Advanced Development	1.8
Sunbury	UGI Energy Services	2017	200,000	34.5	Early Development	1.6
Central Tioga County Extension (TCE2)	Empire Pipeline	-	260,000	25.0	Announced	1.4
Southcross Webb Pipeline	Southcross Energy Partners	-	292,113	94.0	Construction Begun	1.3
Southern Indiana Market Lateral	Boardwalk Pipeline Partners	2016	53,500	30.0	Early Development	1.0

Note: SNL guarantees coverage on natural gas pipeline projects longer than 10 miles, storage projects over 0.1 Bcf and LNG terminals filed with FERC and that are over 0.1 Bcf. SNL does not comprehensively cover projects below this threshold. Bcf - Billion Cubic Feet. *Dth - Decatherm

Sources: S&P Global Market Intelligence; SNL Financial.

GAS DEVELOPMENT PROJECTS FOR NATURAL GAS PIPELINES
(arranged by estimated construction cost, year in service, in $, billions ... continued)

PROJECT NAME	PIPELINE	YEAR IN SERVICE	CAPACITY (Dth)*	MILEAGE	DEVELOPMENT STATUS	ESTIMATED CONSTRUCTION COST
Marcellus/Susquehanna to Lackawanna Gathering System	Boardwalk Field Services	-	292,113	26.0	Announced	0.9
Western Kentucky Lateral	Texas Gas Transmission	2016	223,953	22.5	Early Development	0.8
Lycoming East Gathering Pipeline	PVR Partners	-	370,010	25.0	Early Development	0.8
Rock Springs Expansion	Transcontinental Gas Pipe Line	2016	192,000	11.2	Construction Begun	0.8
Dead Horse Lateral Pipeline Project	Fidelity E&P Company	2015	4,869	24.0	Construction Begun	0.7
Marcellus/Tygart Valley Pipeline	Crestwood	-	194,742	42.0	Announced	0.7
Derricks Lake	WBI Energy Transmission	-	194,742	22.0	Postponed	0.6
Elko Area Expansion Project	Paiute Pipeline Company	2015	21,995	35.2	Construction Begun	0.4
Niobrara Lateral	Trailblazer Pipeline Company	-	90,000	16.0	Early Development	0.2
Clarksville Gas and Water Natural Gas Interconnect Pipeline Project	Texas Gas Transmission	2016	52,000	20.8	Early Development	0.2
Ashland Pipeline	Union Electric Company	-	97,371	11.0	Construction Begun	0.1
North Montney Mainline - Aitken Creek Section (Groundbirch Extension)	NOVA Gas Transmission	2016	1,947,420	112.5	Early Development	-
Atlantic Sunrise Expansion/Central Penn North	Transcontinental Gas Pipe Line	2017	850,000	56.4	Early Development	-
Atlantic Sunrise Expansion/Central Penn South	Transcontinental Gas Pipe Line	2017	850,000	122.2	Early Development	-
Bakken Header Supply Lateral	Northern Border Pipeline Company	2017	287,244	64.0	Early Development	-
Cheniere Corpus Christi Pipeline Project	Cheniere Energy	2017	2,190,847	23.0	Advanced Development	-
Magnum Gas Header Pipeline	Magnum Gas Storage	2017	1,168,452	61.5	Advanced Development	-
North Montney Mainline - Kahta Section (Groundbirch Extension)	NOVA Gas Transmission	2017	1,947,420	74.6	Early Development	-
Prairie State Pipeline	AGL Resources, Tallgrass Development	2017	1,460,565	140.0	Announced	-
Revolution Pipeline	Energy Transfer Partners	2017	428,432	100.0	Announced	-
Mountaineer XPress	Columbia Pipeline Group	2018	2,629,017	165.0	Announced	-
North Mist Expansion	Northwest Natural Gas Company	2018	121,714	13.0	Announced	-
Northeast Energy Direct Pipeline (Market Path)	Tennessee Gas Pipeline Company	2018	1,265,823	246.0	Early Development	-
Northeast Energy Direct Pipeline (Supply Path)	Tennessee Gas Pipeline Company	2018	1,168,452	174.0	Early Development	-
Oregon LNG Pipeline	LNG Development Company	2018	1,460,565	87.0	Early Development	-
Sooner Trails Pipeline Project	NextEra Energy, Southern Star Central	2018	1,168,452	250.0	Announced	-
Washington Expansion Project	Northwest Pipeline	2018	750,000	140.0	Announced	-
North-South Expansion Project	San Diego Gas & Electric Co., Southern California Gas Company	2019	778,968	63.0	Early Development	-
Northwest Market Access Expansion (Trail West)	TransCanada	2019	292,113	106.0	Announced	-
Spectra Energy and BG Group Natural Gas Transportation System	BG Group, Spectra Energy	2019	4,089,581	525.0	Announced	-
Texas Eastern Stratton Ridge Expansion Project	Texas Eastern Transmission	2019	322,000	16.0	Announced	-
Alaska Stand Alone Pipeline Project	State of AK	2020	486,855	757.0	Announced	-
Port Arthur Pipeline Project	Sempra Energy	2020	1,557,936	34.0	Announced	-
Stage 3 Corpus Christi	Cheniere Energy	2021	2,044,791	22.0	Announced	-
Alaska Pipeline Project	Exxon Mobil, State of AK	2022	3,407,984	800.0	Announced	-
Downeast Pipeline	Kestrel Energy	-	608,369	29.8	Postponed	-
Eastern Mainline Project	TransCanada	-	550,000	155.0	Early Development	-
Eureka Hunter Pipeline	Magnum Hunter Resources, Morgan Stanley Infrastructure	-	194,742	182.0	Construction Begun	-
Pacific Trail Pipeline	Woodside Petroleum, Chevron Canada	-	3,894,839	298.0	Advanced Development	-
Pennstar Pipeline	UGI Energy Services, Columbia Pipeline Group	-	500,000	125.0	Announced	-
Renaissance Gas Transmission	Spectra Energy	-	1,217,137	230.0	Postponed	-
Rich Eagle Ford Mainline Expansion (REM) Phase 3	Energy Transfer Partners	-	194,742	37.0	Announced	-
West Range Pipeline - Mesaba Energy Project	Excelsior Energy	-	204,479	14.1	Announced	-

Note: SNL guarantees coverage on natural gas pipeline projects longer than 10 miles, storage projects over 0.1 Bcf and LNG terminals filed with FERC and that are over 0.1 Bcf. SNL does not comprehensively cover projects below this threshold. Bcf - Billion Cubic Feet. *Dth - Decatherm

Sources: S&P Global Market Intelligence; SNL Financial.

Although US gas storage capacity is located in 30 states, eight states (Michigan, Illinois, Texas, Pennsylvania, Louisiana, Ohio, California, and West Virginia) account for about two thirds of the total as of March 2016. Numerous gas storage projects are in progress for the purpose of accommodating increased gas usage and enhancing reliability. The added storage capacity will likely result in additional gas purchases during off-peak months to refill the storage fields in advance of the winter season, therefore helping to smooth seasonal price fluctuations by increasing nonpeak demand and decreasing peak demand

LDCs: The Downstream Segment

Local distribution companies (LDCs) occupy the downstream segment of the gas industry, the LDCs take gas from interstate pipelines and distribute it to a broad range of customers, including residential, commercial, industrial, and power generation. They perform this service under a monopoly concession and are subject to rate regulation. Some companies run LDCs as stand-alone operations but in recent years, independent LDCs have become progressively rare. Following regulatory reforms that helped ease restrictions on mergers by gas and other utilities, most LDCs are now owned by larger holding companies that also own other businesses, including other regulated gas and electric utilities, as well as unregulated businesses that may or may not be related to energy.

It is important to bear in mind that LDCs perform two related, but distinct, services: the delivery of gas, as well as the procurement and sale of gas to the customer. LDCs deliver gas to customers through pipeline networks they build and maintain, and attempt to earn a profit for the provision of that service. In addition, they procure gas and sell it to customers at cost, and no profit is earned for this service. In both cases, state officials regulate the rates that LDCs can charge, and they have no guarantee that state regulators will allow them to recover fully the cost of gas sold to customers.

Competitive Environment: Different End Markets, Different Needs

Natural gas provided about 29% of the US net energy consumed in 2015 and 33% in the first two months of 2016, a share that the EIA expects to be somewhere between 32% and 33% by 2040.

However, S&P Global Market Intelligence thinks that there is potential for natural gas to have share in energy demand, to rise even further than what the EIA estimates suggests, predicated on two concepts. First, burgeoning supplies, courtesy of the shale gas revolution. Second, potential fuel substitution by customers, and specifically switching away from coal, which we see as hampered by a litany of environmental woes.

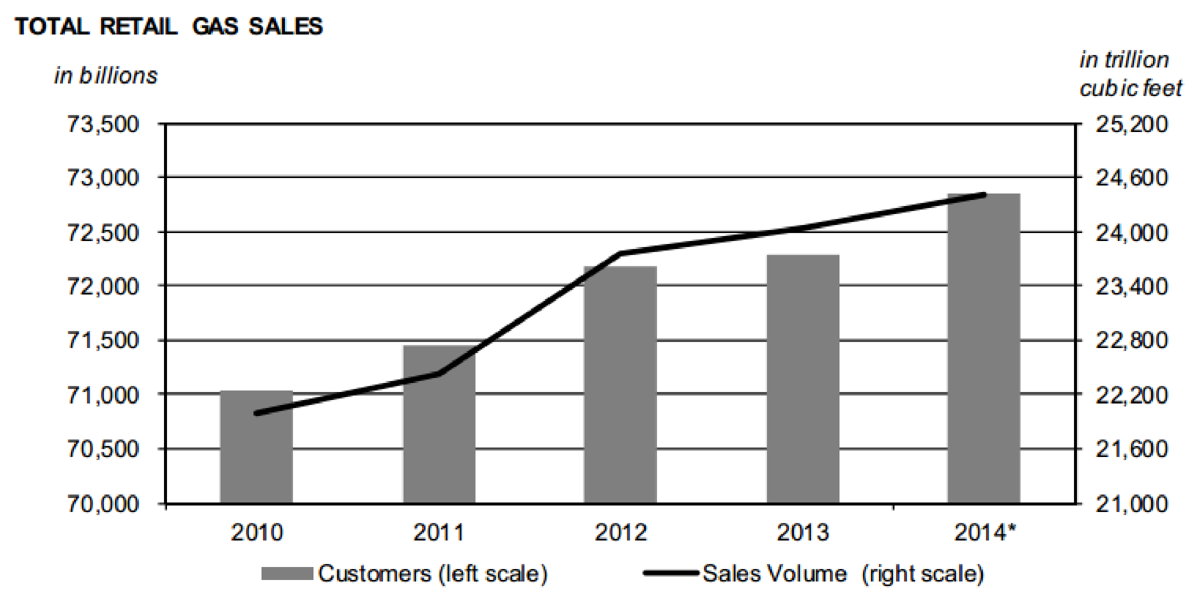
The healthy development of shale gas, and the subsequent development of shale oil (which brings with it associated gas) have generated a substantial deluge of incremental production in the natural gas market.

Residential, commercial, and industrial customers, as well as electric power plants, use natural gas for a variety of purposes, including heat, power generation, and as the raw material for products such as chemicals and fertilizer. Each group exhibits distinctly different responses to changing weather patterns, price levels, and economic activity. However, before the gas even reaches these customers, some of it is used for other purposes. In the first three months of 2016, processors used 396 bcf for lease and plant fuel in gas processing plants, and pipelines used 257 bcf for fuel to power compressors used to move the gas, according to a review released by the EIA in June 2016. Thus, of the estimated 8 quadrillion Btu of natural gas consumed in the US in the first three months of 2016, about 92% reached various end users.

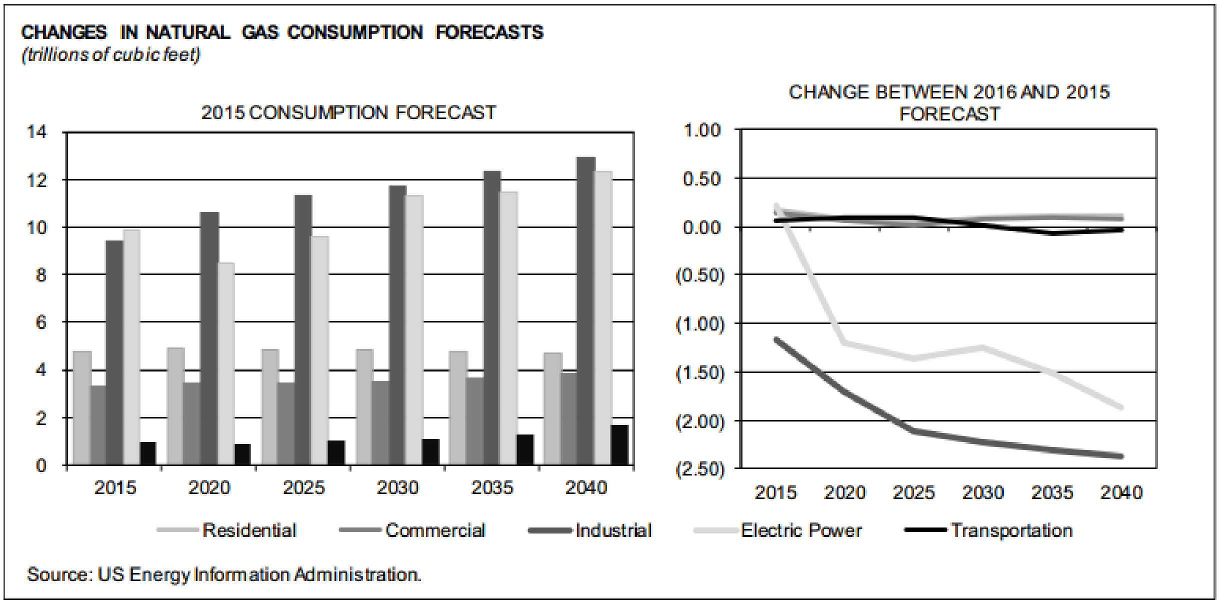
In 2015, processors used 1,578 bcf for lease and plant fuel in gas processing plants, and pipelines used 894 bcf for fuel to power compressors used to move the gas. Thus, of the estimated 28 quadrillion Btu of natural gas consumed in the US last year, about 91% reached various end users.

In 2014, total retail gas sales reached 24.4 tcf, and revenue for bundled gas services, including transportation, distribution, and the natural gas itself totaled $71.9 billion, according to SNL.

LDCs classify their customers as either firm or interruptible. Industrial customers, as well as some commercial customers, have the option of choosing firm gas supply, irrespective of their level of demand, for a correspondingly higher price. For customers that can accommodate temporary interruptions or switch to alternative fuels, interruptible service and the price advantage that it offers might be preferable. Residential customers always receive firm service.



*Latest available.
Sources: S&P Global Market Intelligence; SNL Financial.



Electricity Generation

In 2015, electric power generators became the largest segment of natural gas customer, with relatively few customers accounting for about 35.2% of US gas delivered to consumers. In the first three months of 2016, electric power accounted for 26.9% of total natural gas consumption.

Gas-fired power-generation capacity has experienced immense growth in the US in recent years, for several reasons. Shorter construction times and lower capital investment requirements than other types of power plants made gas-fired power plants an attractive investment during a time of rising electricity prices. New combined-cycle technology has increased the efficiency of gas-fired generation, and due to concern over the environmental impact of coal-fired and nuclear generation, more gas-fired plants are encouraged.

Power generators are even more sensitive to the changing prices of natural gas than industrial users, operating only when electricity prices are high enough to make burning gas for power profitable. Power generators' Gas consumption fell by almost 10% in 2003, when rising gas prices made it less profitable to burn as a fuel for generating power. In the EIA's *Annual Energy Outlook* (AEO) 2015 Reference case, expected capacity additions from 2013 to 2040 total 287 GW, which include new plants in the power sector alongside end-use generators.

Short-term natural gas demand patterns for electric power generators can be affected by several factors other than price. Weather-related events—as well as other developments, such as plant outages, that can raise or lower electricity prices—can cause sudden spikes in gas demand. The rising share of gas demand from electric power producers has created a new "summer peak" in demand, as the use of gas-fired power generators is increased during periods of hot weather in order to meet higher power demand for air conditioning.

The Industrial Market

Industrial consumers were the largest source of demand for natural gas in 2014, accounting for about 34.2% of the total consumer volumes. In 2015, the industrial segment constituted the second largest segment, accounting for 33.1% of total natural gas consumption. In the first three months of 2016, this segment was responsible for 29.9% of natural gas usage, leading all segments so far this year. As per the projections done by EIA, total natural gas consumption in the industrial market will increase from 8.0 quadrillion Btu in 2013 to 9.9 quadrillion Btu in 2040. Natural gas is used in the industrial sector for heat and power, bulk chemical feedstock's, natural gas-to-liquids (GTL) heat and power, and lease and plant fuel.

Consumption by industrial users tends to be more sensitive to changes in economic activity and price than commercial or residential demand, because industrial customers have greater ability, and incentive, to alter their consumption as the market forces shift. Because demand per customer is much larger than it is for commercial or residential users, one industrial customer's decision is going to have a larger impact on total demand.

The Residential Market

Residential gas users accounted for about 16.8% of natural gas volumes delivered to customers in 2015. In the first three months of 2016, residential gas consumers accounted for 25.0% of total consumer volumes. The residential customers supply the lion's share of utility profits by paying substantially higher prices than industrial or commercial customers do despite being more expensive to supply because of the billing and customer service infrastructure required. The 2015 yearly average for residential natural gas prices was $10.36 per thousand cubic feet (Mcf) which was 31.5% higher than commercial prices (at $7.88/Mcf), and 169.8% higher than average industrial prices (at $3.84/Mcf), as per the EIA.

Residential natural gas demand is used mostly for space heating, although that demand is confined mainly to winter months. Residential consumers also use gas to power home appliances such as water heaters, stoves, clothes dryers, and fireplaces. Although residential customers' overall natural gas demand rises and falls with the severity of winter weather, and is subject to other factors, such as population growth and housing trends, the use of natural gas per residential customer is in a long-term decline.

The EIA projects in its 2015 Annual Energy Outlook that delivered energy consumption per household is likely to drop about 0.8% per year between 2015 and 2020, assuming normal weather patterns, which would mainly be due to continuing penetration of efficient gas furnaces and appliances.

The Commercial Market

Commercial customers comprise nonmanufacturing businesses such as hotels, restaurants, wholesalers, retailers, and other service-oriented businesses. Natural gas used by state and federal agencies for nonmanufacturing purposes counts as commercial demand. The commercial market accounted for 13.0% of total natural gas consumption in 2014, 11.7% in 2015, and 14.9% in the first three months of 2016.

As compared to the residential customers, gas demand for commercial customers is somewhat less seasonal. Slightly more than half of all commercially consumed gas is used for space heating, with the remainder used for water heating, cooking, and various other purposes. Change in energy intensity of commercial businesses, as new businesses emerge and others close down, can also account for some fluctuation.

Regulatory Environment

The Legal Battle over the CPP

In an effort to reduce carbon emissions 32% nationwide by 2030, the Environmental Protection Agency (EPA), set standards to limit carbon dioxide ($CO2$) emissions from new, modified, and reconstructed power plants, through the Clean Air Act (CAA) on August 3, 2015. It is said that power plants would be the largest stationary source of carbon pollution in the US.

Under this regulation, new and reconstructed natural gas plants are limited to 1,000 pounds of CO2 per megawatt-hour on a gross-output basis (lb Cos/MWh-gross) emission—applicable to all sizes of base load units. For new coal-fired power plants, gross emission is not to be more than 1,400 lb Cos/MWh-gross. This is less stringent than the proposed standard of 1,100 CO2/MW gross, according to the EPA. The EPA added that the final standard is achievable by new fossil fuel-fired steam generating units for all fuel types. This reflects information and comments with regard to the cost of implementing carbon capture and storage (CCS) on a new unit.

Part of the CAA is the Clean Power Plan (CPP), under which each state has been assigned its own emission reduction target depending on their facilities' potential performance. To comply with the CPP, each state is required to submit an initial State Implementation Plan (SIP) or regional plan with other states by September 2016, and a final SIP by September 2018. The EPA will take approximately one year to review the SIPs and approve or reject the plan. If a state does not submit an SIP, the EPA will impose a federal plan on that state.

The EPA is facing lawsuits from 27 states, which called the CPP an "illegal" regulation that will destroy the coal market. These states are Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Indiana, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Montana, Nebraska, New Jersey, North Carolina, North Dakota, Ohio, Oklahoma, South Carolina, South Dakota, Texas, Utah, West Virginia, Wisconsin, and Wyoming. On the other side of the fence, the states supporting the CPP are California, Connecticut, Delaware, Hawaii, Illinois, Iowa, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New Mexico, New York, Oregon, Rhode Island, Vermont, Virginia, and Washington. Alaska, Idaho, Nevada, Pennsylvania, and Tennessee have not taken any legal stance on the issue.

On February 9, 2016, the US Supreme Court issued an order halting the implementation of the CPP, including the submission of SIPs, until the US Court of Appeals for the D.C. Circuit decides on the

CPP's legality. In May 2016, the appeals court scheduled an en banc hearing on the case for September 27, 2016.

LDC Regulatory Reforms

A series of regulatory reforms from 1978 (when regulations that set natural gas prices at the wellhead were first loosened) to 2005 (when the repeal of the Public Utilities Holding Company Act (PUHCA), dropped federal restrictions on utility mergers) have created a vastly different operating environment than that which prevailed 38 years ago. Natural gas prices are generally higher and more volatile, energy markets are more competitive, and corporate mergers have created huge, diversified energy companies with trading capabilities across several different energy sources. These developments have generated potential reward in addition to new risks for gas distribution utilities.

In response to this environment over the past decades, gas utilities that were previously independent, have combined with other regulated utilities, as well as with new, unregulated energy-related businesses, to manage these new risks and capture profit offered by new opportunities. As a result, today's LDCs are usually part of a holding company that operates several different businesses. In some instances, LDC operations are the holding company's primary business. Secondary operations may include wholesale gas marketing, unregulated power generation, oil and gas exploration and production (E&P), interstate pipelines and storage, or even non-energy-related businesses such as timber or containerized shipping. In many other cases, LDCs are relatively small parts of large multi-utility or multi-industry companies.

LDCs operate under monopolies that are granted by a state or municipality and that cover a particular service area. State utility commissions regulate just about every aspect of an LDC's activities, including what it can charge for delivery and for gas supply. Often known as public utility commissions (PUCs) or public service commissions (PSCs), state regulators are responsible for ensuring the safe and reliable access to gas on an equitable basis and, in some cases, to promote competition.

State utility commissions usually consist of a board of three or more members appointed by the state's governor and confirmed by the legislature. (Some states elect utility commissioners by popular vote.) The commissions often employ a large staff, including attorneys and accountants, to evaluate information filed by utilities regarding potential rate changes and to assist commissioners in making decisions. Utility commissions may regulate one or more natural gas utilities as well as other businesses, such as electric and water utilities, telecommunications providers, and cable television operators.

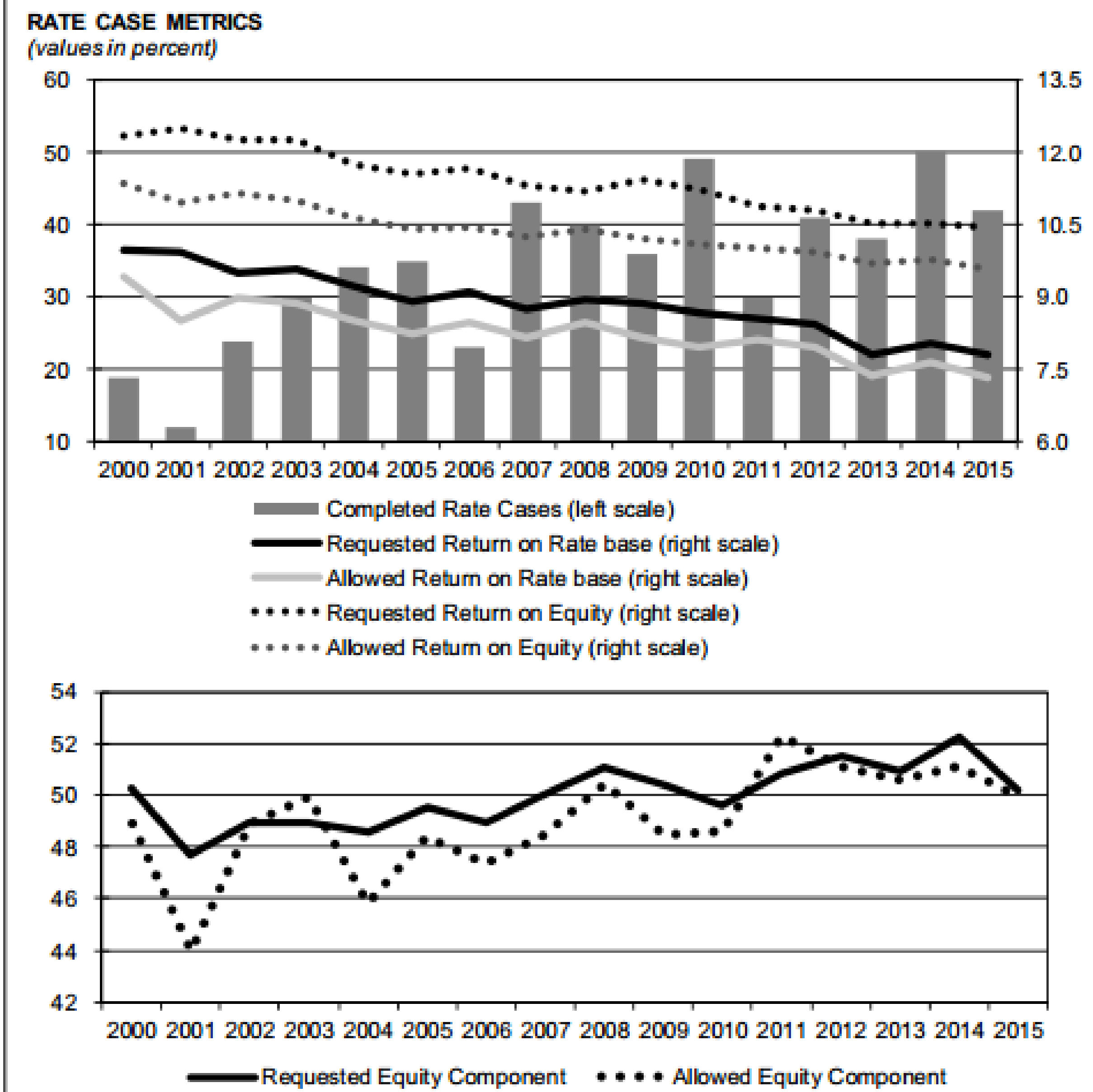
In addition to setting rates of service, regulations are issued by a state utility commission which covers other important aspects of an LDC's operations. It oversees environmental performance, monitors the LDC's operations to ensure that it complies with relevant laws, and enforces universal service obligations. It has authority to approve or deny corporate mergers, the sale of facilities from one party to another, and even such financing activities as bond issues or intracompany fund transfers.

A recent development among the utility commissions is allowing LDCs to add pipeline replacement costs to their rate base without undergoing a gas rate case. This decision was brought about by the great need to replace pipelines that are already in service for more than 50 years. By allowing LDCs to immediately start earning a return from their capital expenses, it stabilizes gas firms' finances and spurs more capital expenditure for infrastructure maintenance.

Ratemaking. The greatest power that state utility commissions hold over LDCs is the ability to set the rates that LDCs charge for delivery and for gas supply. As a practical matter, the delivery charge is the more complex to set, since it has to allow the LDC to earn a profit. Gas supply charges which are not free of controversy, are more an issue of reimbursement, though disputes can and often do arise over whether a gas supply charge was prudently incurred.

The rates of a natural gas utility for its delivery service are mostly set on a "cost-of-service" basis; that is, rates are calculated to generate enough revenue for the utility to recover its operating costs and earn a fair return for shareholders. This makes the relationship between a utility and its regulatory commission an important determinant of both its current profitability and its long-term growth prospects.

In general, the ratemaking process begins with a regulated utility's request for a change in rates when the current rate schedule expires. The process of deciding a utility's allowed rates is known as a "rate case." In addition to the change in rates requested, there may be simultaneous negotiations between the company and the commission on any other issues that one or both sides want to address, such as customer complaints, infrastructure investment, environmental issues, or reliability problems.



Sources: S&P Global Market Intelligence; SNL Financial.

The first step in the rate case is to determine the cost which would be incurred to maintain and operate the distribution system as well as the cost of any needed capital improvements. Companies calculate this amount by totaling their operating and maintenance expenses, asset depreciation, and taxes over a hypothetical period known as a "test year" that has been normalized to eliminate any unusual or one-time incidents. The commission must decide whether to allow each expense item submitted by the LDC. If the commission denies an item, its cost must be borne by the utility's shareholders. Disputes often arise over whether ratepayers should or should not reimburse a particular cost.

In 2015, there were 37 gas rate cases completed with an average authorized ROE of 9.6%, a return on rate base (RORB) of 7.4%, and a common equity component of 49.5%. Conversely, in 2014, these completed cases had an average requested ROE of 8.0%, RORB of 7.7%, and common equity component of 51.1%.

Setting a Utility's Rate of Return. After determining the utility's expenses, an appropriate rate of return for the utility is negotiated for the utility's management by the regulators, this rate would provide an adequate incentive for investors to own equity in the LDC and thus ensure it is adequately capitalized to provide acceptable service. Deciding what level of return the company should receive is often the most controversial part of the rate case—and a process that is as much art as it is science.

For investor-owned utilities, the return is usually calculated as the percentage of the utility's assets used to deliver service that is needed to cover the utility's cost of capital. Cost of capital is defined as the sum of the cost of debt service, preferred stock dividends, and a fair return for common stockholders. While the cost of debt service and preferred stock dividends is easy to establish, the appropriate return for common stockholders is more difficult to ascertain. Commissions use such methods as comparable company analysis, discounted cash flow, and risk premium analysis (such as the capital asset pricing model) to determine an appropriate return on common equity. In some instances, a utility commission may desire to set a rate of return that is not equivalent to the utility's cost of capital, as either a reward or punishment for management decisions and operating performance.

It is to be kept in mind that in setting the rate of return, the utility commission does not guarantee that the LDC will actually earn that rate, but instead gives the LDC the opportunity to earn that rate. Achieving the allowed rate of return requires sound management and operating skill, and poor decisions can lead to the realized rate of return remaining significantly below the allowed rate.

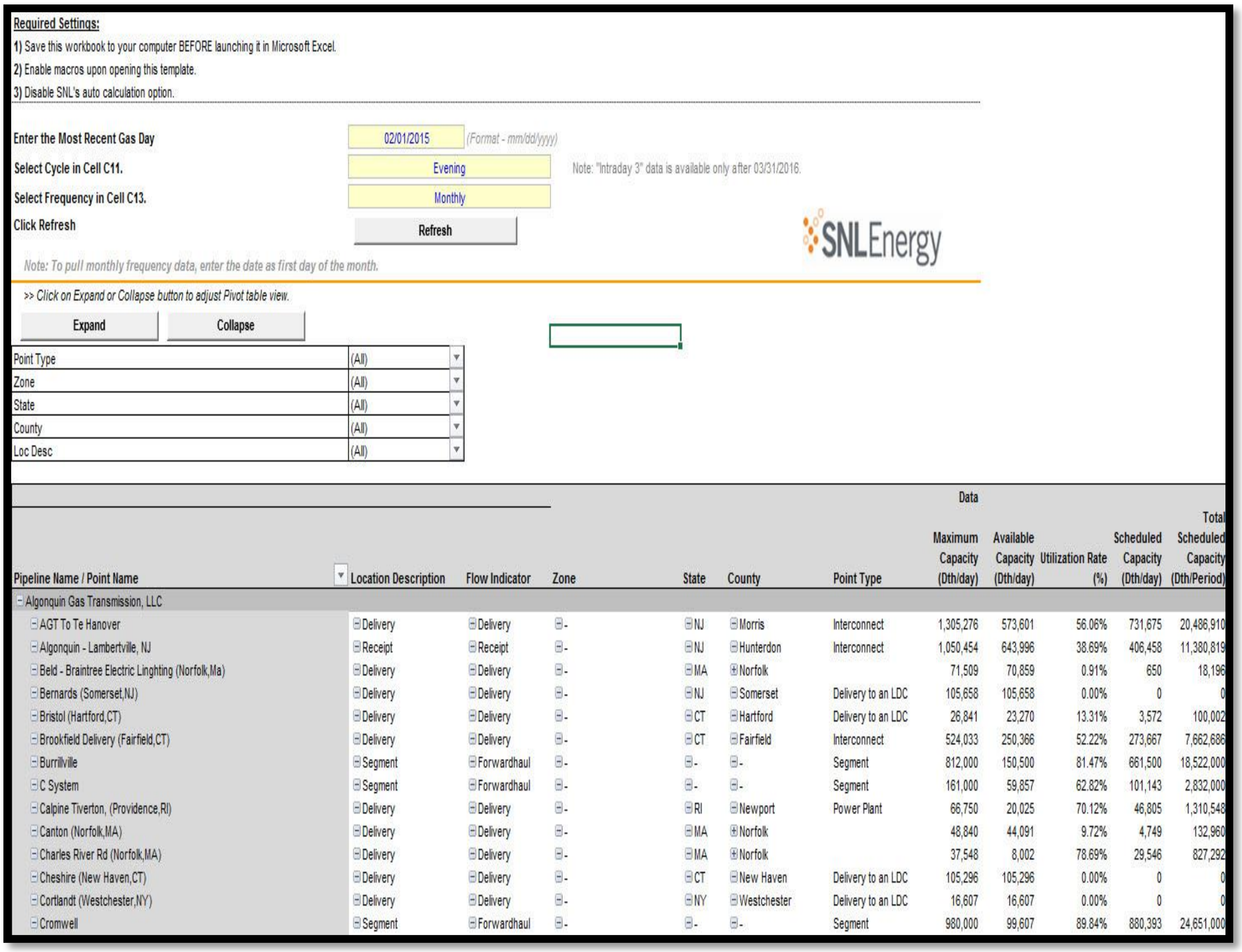
Once the utility's full revenue requirement (costs, plus a fair return) has been identified, that sum then has be allocated among the different classes of gas consumer: industrial, residential, commercial, and power generators. Industrial rates tend to be the lowest, because of industrial customers being high-volume users and easier to service than residential accounts. Allocations can be controversial, since one customer group may argue that it is being forced to subsidize another.

After it has been determined how much each class of customer will pay in total, the structure of the charges is determined in a process known as "rate design." Rate designs vary considerably and can include fixed per-customer charges, minimum bills, charges per therm (a unit of heating value), or some combination of these.

Usage of Template & Client Usage Number

The significance of operational capacity by point plays a very critical role in financial and operational analysis of the company. To analyze the operational effectiveness of any gas company or LDC we use the flow capacity of natural gas as a tool to measure how "liquid" in terms of transporting natural gas the company is capable of. The natural gas flow from the company is reported at different levels and varies from different types of point.

The type of points covered by SNL include of Interconnect, power plant, compressor, exchange point and standalone meter. To analyze the operational capacity by point for natural gas pipelines in US market we scrubbed the raw data from informational postings of the natural gas and standardized it tobe presented in a standardized manner.



Required Settings:
1) Save this workbook to your computer BEFORE launching it in Microsoft Excel.
2) Enable macros upon opening this template.
3) Disable SNL's auto calculation option.

Enter the Most Recent Gas Day: 02/01/2015 (Format - mm/dd/yyyy)
Select Cycle in Cell C11.: Evening — Note: "Intraday 3" data is available only after 03/31/2016.
Select Frequency in Cell C13.: Monthly
Click Refresh: Refresh

SNLEnergy

Note: To pull monthly frequency data, enter the date as first day of the month.

>> Click on Expand or Collapse button to adjust Pivot table view.

Expand | Collapse

Point Type	(All)
Zone	(All)
State	(All)
County	(All)
Loc Desc	(All)

Pipeline Name / Point Name	Location Description	Flow Indicator	Zone	State	County	Point Type	Maximum Capacity (Dth/day)	Available Capacity (Dth/day)	Utilization Rate (%)	Scheduled Capacity (Dth/day)	Total Scheduled Capacity (Dth/Period)
Algonquin Gas Transmission, LLC											
AGT To Te Hanover	Delivery	Delivery	-	NJ	Morris	Interconnect	1,305,276	573,601	56.06%	731,675	20,486,910
Algonquin - Lambertville, NJ	Receipt	Receipt	-	NJ	Hunterdon	Interconnect	1,050,454	643,996	38.69%	406,458	11,380,819
Beld - Braintree Electric Linghting (Norfolk,Ma)	Delivery	Delivery	-	MA	Norfolk		71,509	70,859	0.91%	650	18,196
Bernards (Somerset,NJ)	Delivery	Delivery	-	NJ	Somerset	Delivery to an LDC	105,658	105,658	0.00%	0	0
Bristol (Hartford,CT)	Delivery	Delivery	-	CT	Hartford	Delivery to an LDC	26,841	23,270	13.31%	3,572	100,002
Brookfield Delivery (Fairfield,CT)	Delivery	Delivery	-	CT	Fairfield	Interconnect	524,033	250,366	52.22%	273,667	7,662,686
Burrillville	Segment	Forwardhaul	-	-	-	Segment	812,000	150,500	81.47%	661,500	18,522,000
C System	Segment	Forwardhaul	-	-	-	Segment	161,000	59,857	62.82%	101,143	2,832,000
Calpine Tiverton, (Providence,RI)	Delivery	Delivery	-	RI	Newport	Power Plant	66,750	20,025	70.12%	46,805	1,310,548
Canton (Norfolk,MA)	Delivery	Delivery	-	MA	Norfolk		48,840	44,091	9.72%	4,749	132,960
Charles River Rd (Norfolk,MA)	Delivery	Delivery	-	MA	Norfolk		37,548	8,002	78.69%	29,546	827,292
Cheshire (New Haven,CT)	Delivery	Delivery	-	CT	New Haven	Delivery to an LDC	105,296	105,296	0.00%	0	0
Cortlandt (Westchester,NY)	Delivery	Delivery	-	NY	Westchester	Delivery to an LDC	16,607	16,607	0.00%	0	0
Cromwell	Segment	Forwardhaul	-	-	-	Segment	980,000	99,607	89.84%	880,393	24,651,000

We further drill it down to the point level so that the client's and our users are able to see which specific point has any specific capacity of natural gas to be added or is not being utilized to its maximum potential as well. Breaking down by point can help producers and consumers help identify bottle necks so that can tap into the market and make money out of the opportunities in the market.

Instructions:
1. Enter Dates — From: 01/01/2015 To: 02/10/2015 (Format mm/dd/yyyy)
2. Select a Cycle — Evening — Note: "Intraday 3" data is available only after 03/31/2016.
3. Select a View — ScheduledCapacity
4. Enter Point IDs in Row 25 and select Flow Indicator in Row 28 -- (You can look in the Point ID_LookupPage tab to locate your Point ID for which you wish to run the report.)
5. Click Refresh button

Refresh

SNLEnergy

From: January 01, 2015 To: February 10, 2015
Evening
ScheduledCapacity Dth/day

Pipeline Name	Northern Natural Gas Company	Trunkline Gas Company, LLC	Tennessee Gas Pipeline Company, L.L.C.	Colorado Interstate Gas Company, L.L.C.	El Paso Natural Gas Company, L.L.C.	Northern Border Pipeline Company
Point ID	30	33478	10035	34424	971	34515
Point Name	ETC Sunray Plant	WLA To Longville	E Oh Gas/TGP Gilmore Sales Tuscaraw	Parachute Creek Lateral South	ISJCMPLX	Flow Past Welcome
Point Type	Gathering	Segment	Delivery to End User	Mainline	Gathering	Segment
Flow Indicator	BiDirectional	LineCapacity	Delivery	North	Receipt	South
	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity
02/10/2015	68,506.00	740,000.00	10,420.00	62,651.00	530,985.00	2,167,034.00
02/09/2015	66,209.00	740,000.00	9,970.00	60,488.00	572,685.00	2,070,738.00
02/08/2015	66,209.00	740,000.00	9,988.00	60,488.00	566,973.00	2,070,745.00
02/07/2015	66,209.00	740,000.00	9,986.00	60,488.00	570,227.00	2,070,745.00
02/06/2015	64,016.00	740,000.00	9,720.00	85,382.00	552,095.00	2,039,791.00
02/05/2015	59,006.00	740,000.00	18,060.00	88,356.00	538,743.00	2,193,422.00
02/04/2015	66,158.00	740,000.00	10,220.00	80,271.00	511,177.00	2,155,299.00
02/03/2015	63,465.00	740,000.00	10,320.00	75,293.00	542,102.00	2,039,739.00
02/02/2015	63,506.00	740,000.00	10,320.00	85,963.00	570,184.00	2,101,697.00
02/01/2015	63,506.00	740,000.00	10,323.00	85,963.00	567,882.00	2,088,016.00
01/31/2015	69,600.00	740,000.00	7,642.00	90,067.00	548,051.00	2,157,752.00
01/30/2015	69,600.00	740,000.00	7,642.00	65,067.00	547,723.00	2,052,251.00
01/29/2015	64,800.00	740,000.00	7,648.00	64,317.00	487,755.00	2,085,984.00

Pipeline Name	Bison Pipeline LLC	Transcontinental Gas Pipe Line Company, LLC	Texas Eastern Transmission, LP	Colorado Interstate Gas Company, L.L.C.	Transcontinental Gas Pipe Line Company, LLC	Ruby Pipeline, L.L.C.
Point ID	34521	4643	32841	32677	4577	33772
Point Name	Flow Past Buffalo	Pine View M3617 MP 784.66	Lufkin	Drennan Air Blend Constraint	Scott Mountain M3601 MP 784.66	Ruby East Constraint
Point Type	Segment	Interconnect	Segment	Mainline	Interconnect	Mainline
Flow Indicator	North	Receipt	Backhaul	East	Receipt	West
	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity	ScheduledCapacity
02/10/2015	139,999.00	1,057,956.00	8,000.00	50,704.00	1,219,191.00	469,619.00
02/09/2015	145,000.00	1,016,953.00	-	55,736.00	1,225,966.00	432,816.00
02/08/2015	145,000.00	974,528.00	-	55,737.00	1,225,965.00	432,816.00
02/07/2015	145,000.00	969,359.00	-	45,783.00	1,225,965.00	460,825.00
02/06/2015	142,500.00	1,086,065.00	2,000.00	68,486.00	1,277,605.00	480,798.00
02/05/2015	142,500.00	1,181,678.00	-	35,682.00	1,214,048.00	460,285.00
02/04/2015	142,501.00	1,011,179.00	9,000.00	59,844.00	1,284,178.00	465,450.00
02/03/2015	142,500.00	989,662.00	29,000.00	59,845.00	1,299,685.00	522,429.00
02/02/2015	142,500.00	1,008,872.00	28,000.00	59,845.00	1,367,922.00	468,802.00
02/01/2015	142,500.00	1,047,633.00	46,000.00	59,944.00	1,347,357.00	467,987.00
01/31/2015	158,001.00	1,069,746.00	76,000.00	84,892.00	1,340,609.00	484,944.00
01/30/2015	158,001.00	1,076,203.00	41,000.00	82,342.00	1,355,483.00	500,367.00
01/29/2015	158,001.00	1,113,319.00	50,000.00	82,740.00	1,369,814.00	423,038.00

Analyzing the impact of these operational caveats of the natural gas companies we see how the financials get impacted. To see the impact we do a comparative analysis of the Balance Sheet, Cash flow statement and income statement from the regulated side of the companies. In the US sector the natural gas pipeline companies report to the Public Utility commission and at the aggregate level file to the FERC.

We developed a framework to capture the impact on the financial statements and have been engaging clients to use it and produce results and so far in 2016 we have engaged more than 700, 000 clients to use these excel based workbooks.

Core Functionality:
The template replicates the major FERC Form 2 schedules. Each worksheet is a very close representation of the actual FERC Form 2 schedule.
Required Settings:
1) Save this workbook to your computer BEFORE launching it in Microsoft Excel.
2) Disable SNLxl's allow-excel-calculation option. (SNL Financial --> Settings --> Allow Excel Calculation should not be selected)
3) Update References: (SNL Financial > Sharing > Update References)

Instructions:
1) Hit **Update** in **Cell I11** to refresh the Company List. — Update
2) Select Company in **Cell I13** — ANR Pipeline Company
3) Enter Period in **Cell I15.** *(Format: yyyyY/2009Y…yyyyQq/2010Q2)* — 2013Y
4) Refresh Data.
Excel 2003 ►►► SNL Financial > Refresh Data > All Sheets
Excel 2007 ►►► Add-Ins > SNL Financial > Refresh Data > All Sheets

Balance Sheet

ANR Pipeline Company
Ultimate Parent : TransCanada Corporation

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) *Dollars in Thousands*

Page No.	Line No.	Title of the FERC Account	Acct No.	Ref. Page No.	Year Ended 12/31/2013	12/31/2012	12/31/2011	12/31/2010	12/31/2009
110	1	UTILITY PLANT							
110	2	Utility Plant	101-106,114	200-201	3,483,747	3,391,036	3,866,187	3,893,412	3,846,354
110	3	Construction Work in Progress	107	200-201	58,756	57,054	21,839	9,618	24,786
110	4	TOTAL Utility Plant (Total of lines 2 and 3)		200-201	3,542,503	3,448,090	3,888,027	3,903,030	3,871,139
110	5	(Less) Accum. Provision for Depr., Amort., Depl.	108,111,115		1,941,380	1,925,302	2,349,576	2,404,008	2,361,608
110	6	Net Utility Plant (Total of line 4 less 5)			1,601,123	1,522,788	1,538,451	1,499,022	1,509,531
110	7	Nuclear Fuel	120.1-120.4,		0	0	0	0	0
110	8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies	120.5		0	0	0	0	0
110	9	Nuclear Fuel (Total of line 7 less 8)			0	0	0	0	0
110	10	Net Utility Plant (Total of lines 6 and 9)			1,601,123	1,522,788	1,538,451	1,499,022	1,509,531
110	11	Utility Plant Adjustments	116	122	0	0	0	0	0
		Gas Stored - Noncurrent	**117**		**97,379**	**126,778**	**118,077**	**103,388**	**121,735**
110	16	OTHER PROPERTY AND INVESTMENTS							
110	17	Nonutility Property	121		720	720	720	720	0
110	18	(Less) Accum. Provision for Depreciation and Amortization	122		0	0	0	0	0
110	19	Investments in Associated Companies	123	222-223	0	0	0	0	0
110	20	Investments in Subsidiary Companies	123.1	224-225	40,858	43,614	0	0	0
110	21	(For Cost of Account 123.1 See Footnote Page 224, line 40							
110	22	Noncurrent Portion of Allowances			0	0	0	0	0
110	23	Other Investments	124		0	0	0	0	0
110	24	Sinking Funds	125		0	0	0	0	0
110	25	Depreciation Fund	126		0	0	0	0	0

ANR Pipeline Company
Ultimate Parent : TransCanada Corporation

INCOME STATEMENT

Dollars in Thousands

Page No.	Line No.	Title of the FERC Account	Acct No.	Ref. Page No.	Year Ended 12/31/2013	12/31/2012	12/31/2011	12/31/2010	12/31/2009
		SNL's Utility EBITDA Calculation							
		Operating Revenues-Total			500,336	552,707	593,876	570,439	573,835
	-	Operating Expenses-Total			314,997	260,918	256,311	270,441	289,346
	-	Maintenance Expenses-Total			38,599	41,150	36,685	30,062	26,044
	-	Taxes Other Than Income Taxes-Total			22,093	23,053	23,383	23,368	23,286
	=	**Utility EBITDA (SNL Calculation)**			**124,647**	**227,586**	**277,497**	**246,568**	**235,159**
114	1	**UTILITY OPERATING INCOME - Total**							
115	2	Operating Revenues-Electric	400		0	0	0	0	0
115	2	Operating Revenues-Gas	400		500,336	552,707	593,876	570,439	573,835
115	2	Operating Revenues-Other	400		0	0	0	0	0
114	2	Operating Revenues-Total	400	300-301	500,336	552,707	593,876	570,439	573,835
114	3	Operating Expenses							
115	4	Operation Expenses-Electric	401		0	0	0	0	0
115	4	Operation Expenses-Gas	401		314,997	260,918	256,311	270,441	289,346
115	4	Operation Expenses-Other	401		0	0	0	0	0
114	4	Operating Expenses-Total	401	317-325	314,997	260,918	256,311	270,441	289,346
115	5	Maintenance Expenses-Electric	402	320-323	0	0	0	0	0
115	5	Maintenance Expenses-Gas	402	320-323	38,599	41,150	36,685	30,062	26,044
115	5	Maintenance Expenses-Other	402	320-323	0	0	0	0	0
114	5	Maintenance Expenses-Total	402	317-325	38,599	41,150	36,685	30,062	26,044
115	6	Depreciation Expenses-Electric	403	320-323	0	0	0	0	0
115	6	Depreciation Expenses-Gas	403	320-323	51,680	59,084	61,553	62,900	61,354
115	6	Depreciation Expenses-Other	403	320-323	0	0	0	0	0
114	6	Depreciation Expenses-Total	403	336-338	51,680	59,084	61,553	62,900	61,354
115	7	Depreciation Expense for Asset Retirement Costs-Electric	403.1		0	0	0	0	0
115	7	Depreciation Expense for Asset Retirement Costs-Gas	403.1		129	129	127	125	154
115	7	Depreciation Expense for Asset Retirement Costs-Other	403.1		0	0	0	0	0
114	7	Depreciation Expense for Asset Retirement Costs-Total	403.1	336-338	129	129	127	125	154
115	8	Amort. & Depl. Of Utility Plant-Electric	404-405	336-338	0	0	0	0	0
115	8	Amort. & Depl. Of Utility Plant-Gas	404-405	336-338	7,475	8,592	7,951	8,999	8,855
115	8	Amort. & Depl. Of Utility Plant-Other	404-405	336-338	0	0	0	0	0
114	8	Amort. & Depl. Of Utility Plant-Total	404-405	336-338	7,475	8,592	7,951	8,999	8,855
115	9	Amort. Of Utility Plant Acq. Adj.-Electric	406	336-338	0	0	0	0	0

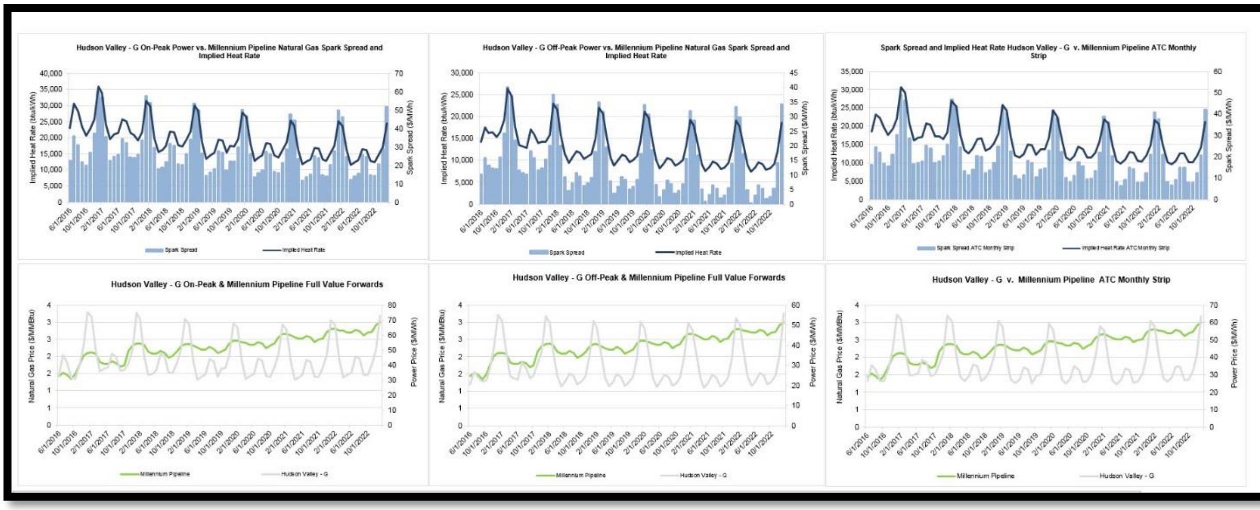
ANR Pipeline Company
Ultimate Parent : TransCanada Corporation

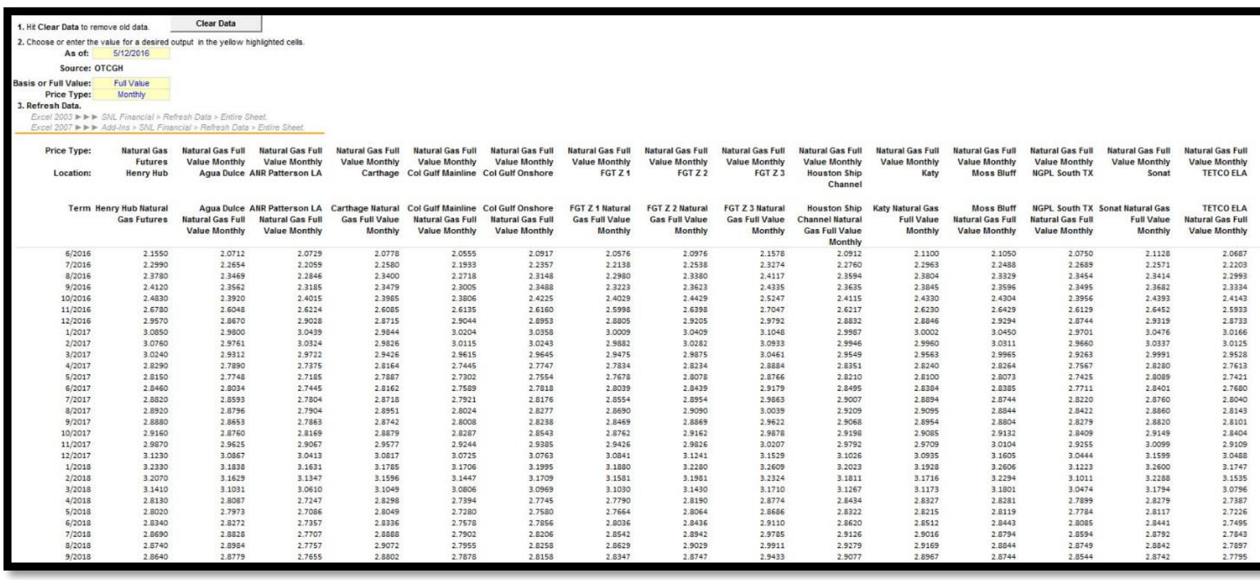
STATEMENT OF CASH FLOWS

Dollars in Thousands

Page No.	Line No.	Title of the FERC Account	Year Ended 12/31/2013	12/31/2012	12/31/2011	12/31/2010	12/31/2009
120	1	**Net Cash Flow from Operating Activities**					
120	2	Net Income (Line 78 on page 116)	24,584	61,101	76,425	48,600	65,816
120	3	Noncash Charges (Credits) to Income:					
120	4	Depreciation and Depletion	51,809	59,213	61,681	63,025	61,508
120	5	Amortization	7,703	8,820	8,179	9,227	9,083
120	6	Deferred income Taxes (Net)	48,651	11,821	50,852	4,762	25,534
120	7	Investment Tax Credit Adjustments (Net)	0	0	0	0	0
120	8	Net (Increase) Decrease in Receivables	-8,635	1,287	5,673	9,353	-42,382
120	9	Net (Increase) Decrease in Inventory	-7,268	2,284	-4,604	789	-2,673
120	10	Net (Increase) Decrease in Allowances Inventory	0	0	0	0	0
120	11	Net (Increase) Decrease in Payable and Accrued Expenses	-21,011	19,418	9,968	-17,580	31,204
120	12	Net (Increase) Decrease in Other Regulatory Assets	-1,743	-333	14,421	85,292	10,218
120	13	Net (Increase) Decrease in Other Regulatory Liabilities	-4,774	21,930	9,195	8,017	-5,368
120	14	(Less) Allowance for Other Funds Used During Construction	3,699	1,843	964	1,400	1,283
120	15	(Less) Undistributed Earnings from Subsidiary Companies	792	845	0	0	0
120	16	Other	-230	-33,072	-29,654	-43,896	11,336
120	17	**Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 16)**	84,596	149,781	201,172	166,187	162,994
120	**20**	**Cash Flows from Investment Activities:**					
120	**21**	**Construction and Acquisition of Plant (including land):**					
120	22	Gross Additions to Utility Plant (less nuclear fuel)	-128,348	-111,223	-97,035	-52,544	-96,486
120	23	Gross Additions to Nuclear Fuel	0	0	0	0	0
120	24	Gross Additions to Common Utility Plant	0	0	0	0	0
120	25	Gross Additions to Nonutility Plant	0	0	0	0	0
120	26	(Less) Allowance for Other Funds Used During Construction	-3,699	-1,843	-964	-1,400	-1,283
120	27	Other	-937	-266	3,150	-535	-3,936
120	**28**	**Cash Outflows for Plant (Total of lines 22 thru 27)**	**-125,587**	**-109,646**	**-92,921**	**-51,679**	**-99,139**
120	30	Acquisition of Other Noncurrent Assets (d)	0	0	0	0	0
120	31	Proceeds from Disposal of Noncurrent Assets (d)	-4,256	-10,954	-5,733	-2,053	-6,503
120	33	Investments in and Advances to Assoc. and Subsidiary Companies	0	0	-59,551	-57,627	0
120	34	Contributions and Advances from Assoc. and Subsidiary Companies	45,221	18,330	0	0	67,964
120	35	Disposition of Investments in (and Advances to)	0	0	0	0	0
120	**36**	**Associated and Subsidiary Companies**					
120	38	Purchase of Investment Securities (a)	0	0	0	0	0
120	39	Proceeds from Sales of Investment Securities (a)	0	0	0	0	0
120a	40	Loans Made or Purchased	0	0	0	0	0
120a	41	Collections on Loans	0	0	0	0	0
120a	43	Net (Increase) Decrease in Receivables	0	0	0	0	0
120a	44	Net (Increase) Decrease in Inventory	0	0	0	0	0
120a	45	Net (Increase) Decrease in Allowances Held for Speculation	0	0	0	0	0
120a	46	Net Increase (Decrease) in Payables and Accrued Expenses	0	0	0	0	0
120a	42	Other Cash-Investing Activities	0	0	0	0	0

Another market getting impacted is the commodity market which helps to drive the financial sector as well. To analyze the commodity we use the spot prices to get an idea about the historical performance and use the forwards and futures to see how they are trading into the future. A nice pictorial representation of this helps to make quick market based decisions so that they are able to leverage on any information available in the market.





1. Hit Clear Data to remove old data. Clear Data

2. Choose or enter the value for a desired output in the yellow highlighted cells.

As of: 5/12/2016

Source: OTCGH

Basis or Full Value: Full Value

Price Type: Monthly

3. Refresh Data.

Excel 2003 ►►► SNL Financial > Refresh Data > Entire Sheet.

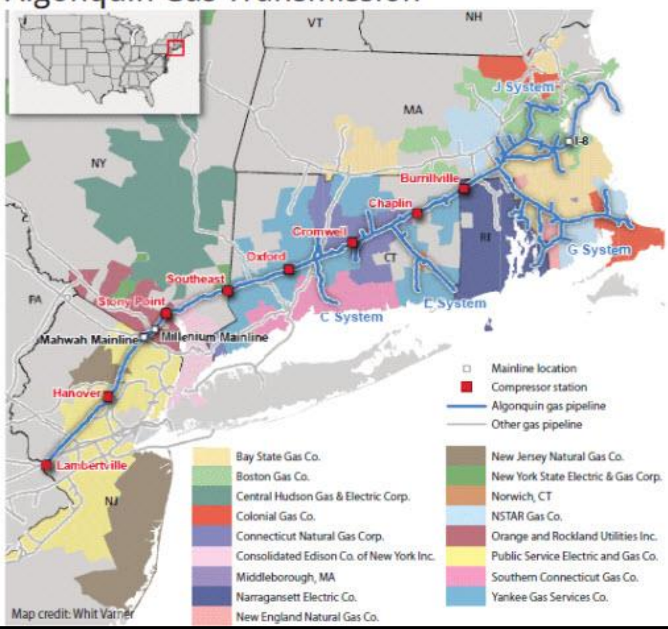
Excel 2007 ►►► Add-Ins > SNL Financial > Refresh Data > Entire Sheet.

Price Type:	Natural Gas Futures	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly	Natural Gas Full Value Monthly
Location:	Henry Hub	Agua Dulce	ANR Patterson LA	Carthage	Col Gulf Mainline	Col Gulf Onshore	FGT Z 1	FGT Z 2	FGT Z 3	Houston Ship Channel	Katy	Moss Bluff	NGPL South TX	Sonat	TETCO ELA
Term	Henry Hub Natural Gas Futures	Agua Dulce Natural Gas Full Value Monthly	ANR Patterson LA Natural Gas Full Value Monthly	Carthage Natural Gas Full Value Monthly	Col Gulf Mainline Natural Gas Full Value Monthly	Col Gulf Onshore Natural Gas Full Value Monthly	FGT Z 1 Natural Gas Full Value Monthly	FGT Z 2 Natural Gas Full Value Monthly	FGT Z 3 Natural Gas Full Value Monthly	Houston Ship Channel Natural Gas Full Value Monthly	Katy Natural Gas Full Value Monthly	Moss Bluff Natural Gas Full Value Monthly	NGPL South TX Natural Gas Full Value Monthly	Sonat Natural Gas Full Value Monthly	TETCO ELA Natural Gas Full Value Monthly
6/2016	2.1550	2.0712	2.0729	2.0778	2.0555	2.0917	2.0576	2.0976	2.1578	2.0912	2.1100	2.1050	2.0750	2.1128	2.0687
7/2016	2.2990	2.2654	2.2059	2.2580	2.1933	2.2357	2.2138	2.2538	2.3274	2.2760	2.2963	2.2488	2.2689	2.2571	2.2203
8/2016	2.3780	2.3469	2.2846	2.3400	2.2718	2.3148	2.2980	2.3380	2.4117	2.3594	2.3804	2.3329	2.3454	2.3414	2.2993
9/2016	2.4120	2.3562	2.3185	2.3479	2.3005	2.3488	2.3223	2.3623	2.4335	2.3635	2.3845	2.3596	2.3495	2.3682	2.3334
10/2016	2.4830	2.3920	2.4015	2.3985	2.3806	2.4225	2.4029	2.4429	2.5247	2.4115	2.4330	2.4304	2.3956	2.4393	2.4143
11/2016	2.6780	2.6048	2.6224	2.6085	2.6135	2.6160	2.5998	2.6398	2.7047	2.6217	2.6230	2.6429	2.6129	2.6452	2.5933
12/2016	2.9570	2.8670	2.9028	2.8715	2.9044	2.8953	2.8805	2.9205	2.9792	2.8832	2.8846	2.9294	2.8744	2.9319	2.8733
1/2017	3.0850	2.9800	3.0439	2.9844	3.0204	3.0358	3.0009	3.0409	3.1048	2.9987	3.0002	3.0450	2.9701	3.0476	3.0166
2/2017	3.0760	2.9761	3.0324	2.9826	3.0115	3.0243	2.9882	3.0282	3.0933	2.9946	2.9960	3.0311	2.9660	3.0337	3.0125
3/2017	3.0240	2.9312	2.9722	2.9426	2.9615	2.9645	2.9475	2.9875	3.0461	2.9549	2.9563	2.9965	2.9263	2.9991	2.9528
4/2017	2.8290	2.7890	2.7375	2.8164	2.7445	2.7747	2.7834	2.8234	2.8884	2.8351	2.8240	2.8264	2.7567	2.8280	2.7613
5/2017	2.8150	2.7748	2.7185	2.7887	2.7302	2.7554	2.7678	2.8078	2.8766	2.8210	2.8100	2.8073	2.7425	2.8089	2.7421
6/2017	2.8460	2.8034	2.7445	2.8162	2.7589	2.7818	2.8039	2.8439	2.9179	2.8495	2.8384	2.8385	2.7711	2.8401	2.7680
7/2017	2.8820	2.8593	2.7804	2.8718	2.7921	2.8176	2.8554	2.8954	2.9863	2.9007	2.8894	2.8744	2.8220	2.8760	2.8040
8/2017	2.8920	2.8796	2.7904	2.8951	2.8024	2.8277	2.8690	2.9090	3.0039	2.9209	2.9095	2.8844	2.8422	2.8860	2.8143
9/2017	2.8880	2.8653	2.7863	2.8742	2.8008	2.8238	2.8469	2.8869	2.9622	2.9068	2.8954	2.8804	2.8279	2.8820	2.8101
10/2017	2.9160	2.8760	2.8169	2.8879	2.8287	2.8543	2.8762	2.9162	2.9878	2.9198	2.9085	2.9132	2.8409	2.9149	2.8404
11/2017	2.9870	2.9625	2.9067	2.9577	2.9244	2.9385	2.9426	2.9826	3.0207	2.9792	2.9709	3.0104	2.9255	3.0099	2.9109
12/2017	3.1230	3.0867	3.0413	3.0817	3.0725	3.0763	3.0841	3.1241	3.1529	3.1026	3.0935	3.1605	3.0444	3.1599	3.0488
1/2018	3.2330	3.1838	3.1631	3.1785	3.1706	3.1995	3.1880	3.2280	3.2609	3.2023	3.1928	3.2606	3.1223	3.2600	3.1747
2/2018	3.2070	3.1629	3.1347	3.1596	3.1447	3.1709	3.1581	3.1981	3.2324	3.1811	3.1716	3.2294	3.1011	3.2288	3.1535
3/2018	3.1410	3.1031	3.0610	3.1049	3.0806	3.0969	3.1030	3.1430	3.1710	3.1267	3.1173	3.1801	3.0474	3.1794	3.0796
4/2018	2.8130	2.8087	2.7247	2.8298	2.7394	2.7745	2.7790	2.8190	2.8774	2.8434	2.8327	2.8281	2.7899	2.8279	2.7387
5/2018	2.8020	2.7973	2.7086	2.8049	2.7280	2.7580	2.7664	2.8064	2.8686	2.8322	2.8215	2.8119	2.7784	2.8117	2.7226
6/2018	2.8340	2.8272	2.7357	2.8336	2.7578	2.7856	2.8036	2.8436	2.9110	2.8620	2.8512	2.8443	2.8085	2.8441	2.7495
7/2018	2.8690	2.8828	2.7707	2.8888	2.7902	2.8206	2.8542	2.8942	2.9785	2.9126	2.9016	2.8794	2.8594	2.8792	2.7843
8/2018	2.8740	2.8984	2.7757	2.9072	2.7955	2.8258	2.8629	2.9029	2.9911	2.9279	2.9169	2.8844	2.8749	2.8842	2.7897
9/2018	2.8640	2.8779	2.7655	2.8802	2.7878	2.8158	2.8347	2.8747	2.9433	2.9077	2.8967	2.8744	2.8544	2.8742	2.7795

The end result of all this effort is smooth work flow creation which helps to do analysis and do market based commentary in the form of data dispatches and reports. These reports help to give up to date information and provide a summary in terms of analyzing the operational capacity date, financial sector analysis, and commodity market analysis in the form of a report published on a frequent basis.

During the week, flows at the Millennium Mainline segment averaged 1.29 Bcf/d for a utilization rate of 83.4%, below the month-to-date average of 85.2% and the December 2014 average of 93.4%. The Southeast and Stony Point compressor stations saw utilization rates of 96.9% and 87.5%, respectively, against the winter 2014 average of 93.6% and 94.5%.

Algonquin Gas Transmission

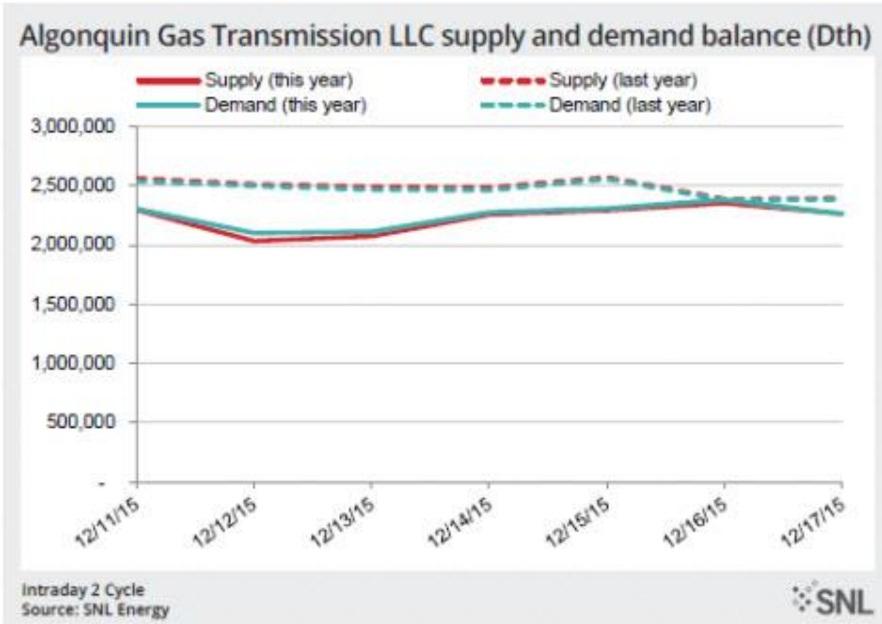


Algonquin Gas Transmission LLC segment utilization (%)

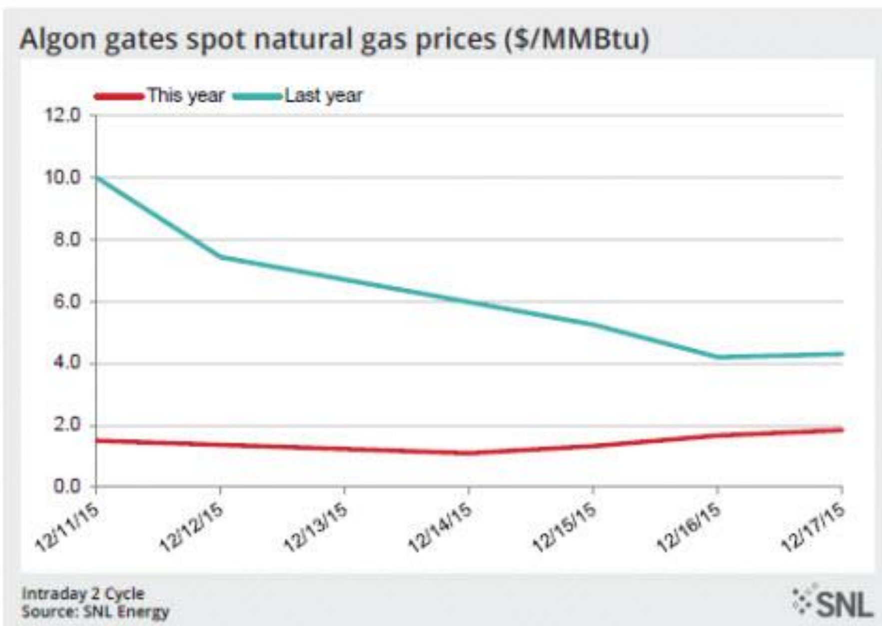
Intraday 2 cycle

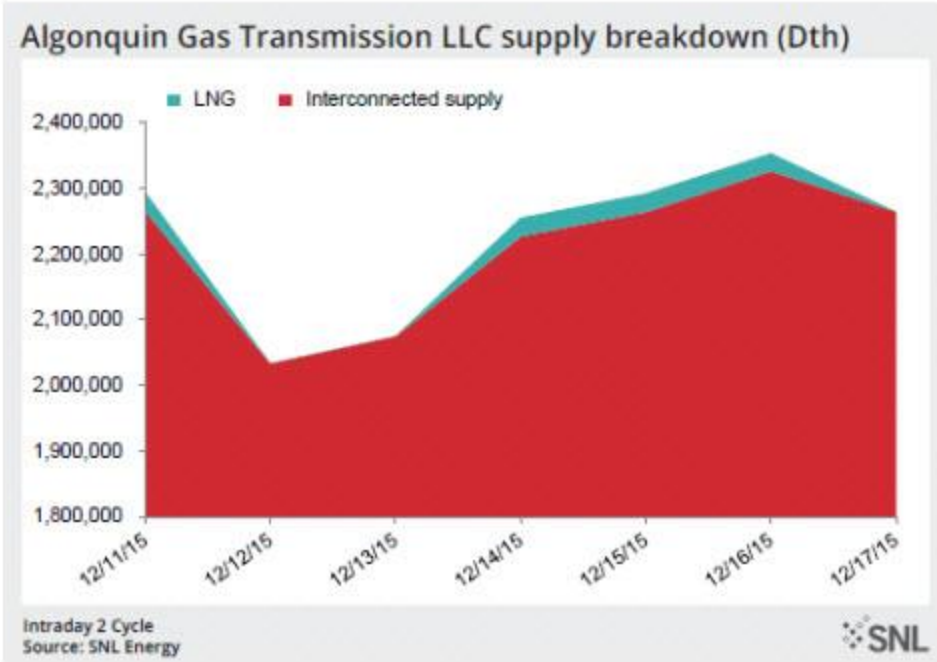
Compressor stations		7-day avg.	MTD avg.	Dec. '14 avg.	Winter-to-date avg.	Prior winter avg.
Burrillville	→	58.5	65.5	78.4	58.1	79.1
Chaplin	→	70.7	77.6	85.9	68.3	85.3
Cromwell	→	78.1	83.8	91.2	75.8	89.6
Hanover	→	NA	NA	NA	NA	0.5
Hanover	←	28.8	29.3	24.9	38.2	20.4
Hanover Lease	←	95.9	98.1	98.0	96.6	98.5
Oxford	→	79.3	86.2	97.7	86.4	93.9
Southeast	→	96.9	98.5	93.4	81.1	93.6
Stony Point	→	87.5	89.1	93.6	90.5	94.5
Mainline locations						
AGT East-to West (I-8)	→	NA	4.4	18.7	2.1	25.7
AGT East-to West (I-8)	←	16.8	15.5	8.0	11.6	14.0
Mahwah Mainline	→	54.8	54.4	62.7	45.4	65.0
Mahwah Mainline Lease	←	7.1	8.2	8.0	6.9	7.7
Millennium Mainline	→	83.4	85.2	93.4	73.6	94.7
Laterals						
C System	→	47.2	51.4	63.1	46.7	59.6
E System	→	45.8	52.3	63.9	49.3	66.8
G System	→	51.6	58.8	71.4	58.1	73.7
J System	→	52.5	53.7	59.9	54.2	55.0

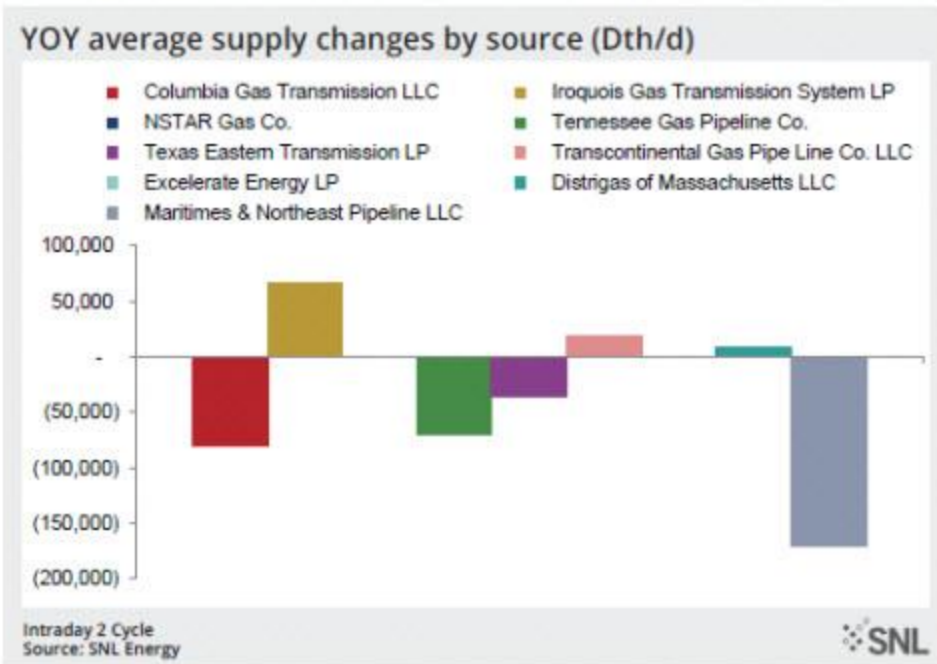
NA = not available
Source: SNL Energy



Spot natural gas prices at Algon Gates reached an index as high as $1.843/MMBtu during the week, as the year over year to $1.490/MMBtu.




Algonquin Gas Transmission LLC supply breakdown (Dth)
LNG
Interconnected supply
2,400,000
2,300,000
2,200,000
2,100,000
2,000,000
1,900,000
1,800,000
12/11/15
12/12/15
12/13/15
12/14/15
12/15/15
12/16/15
12/17/15
Intraday 2 Cycle
Source: SNL Energy
SNL


YOY average supply changes by source (Dth/d)
Columbia Gas Transmission LLC
NSTAR Gas Co.
Texas Eastern Transmission LP
Excelerate Energy LP
Maritimes & Northeast Pipeline LLC
Iroquois Gas Transmission System LP
Tennessee Gas Pipeline Co.
Transcontinental Gas Pipe Line Co. LLC
Distrigas of Massachusetts LLC
100,000
50,000
-
(50,000)
(100,000)
(150,000)
(200,000)
Intraday 2 Cycle
Source: SNL Energy
SNL

Key Industry Ratios and Statistics

- **Consumption days (hot vs. cold days comparison):**

The pattern of usage of natural gas shows direct proportion to extremes in temperatures. Typical uses occur in form of enclosed spaces for commercial, industrial and residential markets (and are referred to as **"heating day"**). U.S situated in northern hemisphere experiences cold weather from November to February/March. The northern parts of the country typically experience longer and more intense winters (Chicago, New York, etc.). On the other hand southern region has longer summers (Florida, Texas, etc.).

Warm months in summer where customers use air conditioning are referred to as **"cooling degree days"**. This aspect is important because the utility companies producing electricity are increasingly natural gas to drive the generation plants.

Around two third of residential demand side of gas is fulfilled by space heating. Similarly it also satisfies around half of commercial demand. Year-to-year variations in the consumption of natural gas are due to corresponding variation in the severity of weather and climatic changes.

While making projections of future demand for gas the analysts assume that "normal" conditions of weather will occur throughout the duration covering projections. These days are quantified with respect to cooling and heating days. In order to represent the relative warmth or coldness of the atmosphere/air, a degree day is used, which is represents how far above or below the reference temperature has the daily mean temperature deviated. For example if the reference temperature is set at 65 degree Fahrenheit and todays temperature is 35 degree Fahrenheit than we would call today as a "30-degree" heating day. There is an agency of U.S Department of Commerce called The National Oceanic and Atmospheric Administration (NOAA) which calculates these temperatures on a daily basis. The natural variability in the weather will always cause some degree of unpredictability/volatility.

- **Real gross domestic product:**

Despite the weather being the major cause that results in shifts in the gas consumption, this demand of gas which is weather-normalized has historically followed the overall economy. The average growth (annual) in demand for natural gas in the U.S has trailed the GDP growth by being less than three quarters of it. This is due to the fact that economy affects all the major sectors of demand for natural gas. Department of Commerce produces reports covering GDP on quarterly basis.

- **Residential Housing and Construction of new projects:**

A booming economy will accelerate housing projects, renovation projects, etc. Similarly a recession scenario results in more foreclosing and resulting decrease in demand for the natural gas. Due to fact that residential customer offers largest potential for profit for a distribution company offering natural gas, hence the housing starts (i.e. total number of new residential units where the construction has started in a given period) is a significant field for gas industry. Since the individual customers consume fewer fuel than commercial customers and industrial entities hence such a customer pays a substantially higher per unit rate to the utility company. This is the reason why almost two-thirds of revenue for utility gas company comes from such residential companies. Improvements in appliance design reduce the per unit consumption over time.

- **Interest Rates:**

The gas utility companies are very sensitive to the interest rates and available rate of returns as the industry is very capital intensive. Utility rates are determined the regulatory agencies of the respective states. Any change in interest rates is expected to be reflected in the rates charged from the consumer. For example a substantial drop in the interest rates decreases financial costs savings and therefore should result in lower tariff for consumer. On the other end of the spectrum are the investors seeking income in the form dividend on shares and are hence very sensitive to changes in interest rates. In case of rising interest rates the investors may choose to invest elsewhere and receive same returns.

How to analyze a company in this industry

It should be noted that the performance of any gas utility is dependent upon the type of mix in their operations. Typically the companies that own a liquid distribution company (LDC) also have other operation that can include both regulated (as in the case of electricity and pipeline distribution) and also unregulated (power generation assets). Hence each of such operations brings different set of challenges in terms of financial needs, competitive positioning, and market dynamics on the table. The earning from an unregulated generation can be largely volatile especially due to the expected swings can follow a commodity's price.

As a result it is vital to keep these various issues in mind while analyzing a particular LDC.

Competitive Position:

To accurately judge the position where a LDC stands first of the rates it charges from its customers should be compared with the immediate competitors and then compare it with the average rates nationally. Lower rates not only will indicate the focus of a given company on cost control but lower rates generally entail a more positive and healthier relationship with the regulator. It also helps thwart the threat from competitors.

Tracking the competitive threats is vital in light of regulatory reforms as independent gas companies have gradually increased in number where the new players were attracted with the prospect of attracting new customers. Interstate pipeline companies try to bypass LDCs by directly providing gas to large-scale industrial customers.

Hence the major competitive challenges an LDC faces include:

1. Attracting a sufficient number of customers
2. Retaining these customers possibly locking them in through long term contracts.
3. Use bundling, bulk pricing discounts effectively to give the best value for money thereby become preferred choice among new customers.
4. Effectively market and position them apart from the competition.
5. Provide timely and lucrative returns to investors, shareholders without jeopardizing the relationship with creditors, regulators, etc.

Location and Customer Mix

Demand may increase in 3 ways:

1. Bringing in new customers
2. Increased consumption of these customers
3. Any scenario based on combination of the above two options

A growing population and a booming population are hence the most encouraging signs that are most likely going to bring a gradual (or in exceptional cases a sudden) increase in demand. It has been observed over the years that increasing customers do not always translate into proportionate increase in the volume of gas sold. One important reason is the development of efficient appliances.

While analyzing such numbers it is imperative to note that how much residential customers are from the total customers of a LDC. Residential customers hold the key as they represent a more stable stream of revenue. On the other hand the industrial are much more price sensitive. Therefore having a larger residential customer base means lesser reliance of big business customers who might dictate their terms if they make up a large part of the revenue.

On the other hand too much reliance on residential customer is also not advised as normally a residential customer is a full service consumer such that LDC is obligated to always fulfill the demand of this customer no matter how small or varying. This can bring inventory management risk into the equation. Further the need to answer any change in demand can lead to commodity price risk. Add to that the fact that generally the residential consumers' demand is higher at the time of very cold weather that also leads to higher gas prices during those times. This means that a LDC will need to modify their procurement strategy and price hedging strategy. Such modifications are subject to review from regulators who may deem the resulting transformative measures insufficient hence straining the relationship with the regulator.

Regulatory environment

Emerging trends of the regulatory commission that governs the area of operations of an LDC needs to be studied due to the fact that rate of return regulations are devised by such commissions. Some important points to be considered are:

1. How long does commission typically take to approve requests?
2. What sort of mechanisms in the requests for rate reviews can hamper and lengthen the approval process.
3. Which particular legislation has the largest impact driving the process forward?

Gas Supply Demand

Managing the transportation and supply capacity is of paramount importance. Relevant concerns governing the decisions of an LDC's management should be:

1. How much gas is to be bought on the spot market.
2. What is the minimum interrupted capacity needed.
3. Peak demand fulfillment capacity.

Ideally a well-managed LDC will obtain gas from more than one producers who supply it from geographically separate regions. Purchase contracts as well as the storage management operations need to be executed in the most efficient manner. Failure to do so can become problematic due to "hindsight" reviews conducted by the regulators. Repeated failure in any domain may lead to detrimental consequences such cancellation of license etc.

Storage

In order to control the supply as well as the cost of gas a LDC needs to manage its storage capacity. This has two major functions. Firstly, the gas can be accessed in peak demand times. Secondly, gas can be purchased in off-peak seasons at lower rates. The space for storage can either be leased or owned.

Analyzing the Income Statement

Common measures of profitability including net income and earnings-per-share (EPS) cannot be used due to impact unexpected weather changes as well as regulatory constraints on LDC. Instead investors assess the management of financial resources by examining following three parameters in an income statement:

- **Net Revenue**: Although the growth in net revenues is largely predictable, nonetheless, it is beneficial to conduct a retrospective analysis to gauge an accurate expectation for future.
- **Operating expenses:** Emphasis is placed on nonfuel operating and maintenance costs due to wide fluctuations in fuel prices.
- **Interest Expense:** Interest payments are most significant no operating expense due to capital intensive nature of gas utility industry.

Balance Sheet Evaluation

Public utility companies require significant investment in long term assets hence they have larger long term debt than corporations in several industries. Investors are not critical of these high levels of debt due to level of regulation in this industry.

Cash Flow Assessment

Clues can be derived by reviewing the trends of cash flow. It is fundamental to company's survival to meet its ongoing expenses by generating sufficient funds, Rising and growing positive cash flows reduce the dependence on financial institution and hence sustain the expansion ventures through internally generated funds.

Valuation and Performance Measures

- **Return on Equity**
- **Return on Assets**
- **Earnings / fixed asset ratio.** Shows company's ability to pay fixed expenses (e.g. interest expenses)
- **Price to Book ratio.** Shows how much the investors are willing to pay for company's share and hence represent goodwill on investor's part.
- **Price to Earnings Ratio:** Comparing this ratio for a LDC with that of its competitors as well as its past performance.
- **Payments of Dividends.** Shareholders of utility companies are interested in total value derived consisting of both dividend payments as well share appreciation. However dividends form a larger component in the total expected return.

Conclusion

Under expert guidance from our supervisor we intend that this research benefits both academics as well as firms and individuals seeking a sound decision making while analyzing the natural gas sector of the U.S. to enhance the decision making process of investors planning their investments in natural gas companies on the basis of our research. It is hoped through this research the conventional techniques are transformed into a more analytic and encompassing approach that gets reflected in better results and positive implications derived from sound decision making using these results.

Glossary of Important Terms

- **British thermal unit (Btu):** This is the quantitative representation of heat required to raise temperature of 1 pound of water by a single degree.
- **Bypass:** Circumvention of Local Distribution Company by producers to directly sell natural gas to customers.
- **City Gate:** This represents a physical connection between a local utility's pipes and an interstate pipeline.
- **Cost of service:** One of the major determinants of the rate of return and includes all type of expenses, taxes, amortization etc.
- **Degree Day:** In order to represent the relative warmth or coldness of the atmosphere/air, a degree day is used, which is represents how far above or below the reference temperature has the daily mean temperature deviated. For example if the reference temperature is set at 65 degree Fahrenheit and todays temperature is 35 degree Fahrenheit than we would call today as a "30-degree" heating day.
- **Downstream:** Distribution of gas to final end user.
- **Heating Season:** Winter heating season typically begins on 1st November and ends on 31st March.
- **Hedging:** Use of contracts or some other physical resource to minimize or mitigate financial risk.
- **Hub:** An interchange of pipelines standardized as a delivery point so that natural gas futures can be figured.
- **Interruptible service:** Gas service where interruption is permitted on short notice and agreed in the contract.
- **Local Distribution Company (LDC):** Refers to an entity that operates and also owns the system and infrastructure for the distribution of natural gas.
- **Midstream:** Refers to activities taking place after production of gas i.e. distribution, transmission, etc.

- **Normalization:** Adjustments and standardization in data of historic sales, revenues, and expenses to make it conform to normal patterns of weather conditions.
- **Public Utility Commission (PUC):** Regulatory authority governing the implementation of rules, preventing monopoly and monitoring rates in the industry.
- **Rate Base:** The asset value (cash, supplies, capital, etc.) upon which rate of return is permitted to earn.
- **Rate Case:** Refers to negotiation of tariff with regulators.
- **Upstream:** Exploration of fossil fuels
- **Wellhead:** Point of origin (i.e. valves and controls on the well containing gas) in the gas supply.