Exhibit 5.1
Redacted

Gas Supply Portfolio Design

Black Hills Utility Holdings Inc.

Prepared by Aether Advisors LLC

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Executive Summary

Black Hills Utility Holdings Inc. ("BHUH") engaged Aether Advisors LLC ("Aether") to review its current hedging program and to provide recommendations related to long-term hedging of gas supply costs. Aether was to consider whether BHUH should enter into long-term hedges to manage gas supply cost risks. If that was a recommended course of action, the next questions related to the scale of the hedging and how it could be integrated with the current gas and electric utilities' hedging programs. To answer these questions, Aether reviewed BHUH's current hedging program and described different types of hedging instruments BHUH could consider. From there, it looked at the fundamental market drivers impacting natural gas supply, demand, and prices. And Aether ran a stress-test analysis of the aggregated gas supply portfolio to test the effect of different hedging programs across different market scenarios to understand the potential impact on future gas supply costs.

In <u>Part 1 – Current Gas Supply Portfolio Review</u> of its report Aether summarized BHUH's current and prospective gas supply procurement activities, from the perspective of managing price exposure for gas and electric utility customers. In order to assess the hedging program and to provide recommendations for enhancements, Aether reviewed how the gas supply goals accommodated hedging. BHUH's gas supply goals are to 1) provide reasonably priced natural gas; 2) provide a high level of reliability; and 3) mitigate price volatility through its hedging program. Aether reviewed the gas hedging plans for each utility, looking at the hedging program design, the hedging instruments used, and the hedging protocols. Aether also assessed BHUH's use of storage, physical contracts, and financial instruments to manage gas price exposure.

In <u>Part 2 – Gas Supply Hedging Options</u>, Aether described how a utility's hedging program is influenced by its hedging goals. Given BHUH's goals to provide rate stability and to protect customers from market volatility, a long-term term hedging focus is appropriate. The current mix of tools has been effective for protecting against seasonal price spikes in the short-term. But if the objective is to offer more rate stability over an extended time horizon, then the short-term hedging program will not be adequate.

Aether described how U.S. storage capacity has not grown as quickly as total gas demand. As a result, there may be more spot market volatility on super peak days given there is proportionally less storage capacity to meet peaking demand. Storage is an important short-term hedging tool and very appropriate for a short-term program. But storage can only hedge price exposure for a season. Longer-term hedging instruments would provide better rate stability and protect customers more from market price movement over an extended period of time.

Aether provided several medium-term gas supply portfolio options, some of which are used by BHUH for short-term hedging. Aether illustrated the manner in which the instruments would perform depending upon certain market conditions. Aether also described how and when different instruments could be used to achieve certain hedging goals.

With respect to long-term hedging, Aether reviewed the use of long-term contracts, volumetric production payments, and investment in reserves to reduce supply cost volatility and to stabilize gas supply costs for customers. The latter would be consistent with a Cost of Service Gas proposal. Aether reviewed some of the limitations associated with long-term fixed price contracts such as market liquidity constraints and counterparty credit risk. Lastly, Aether discussed operational considerations with owning gas production, suggesting several approaches to optimize the investment and to mitigate potential risks.

Since a long-term fixed price supply contract or resource has long-term rate implications, it should provide sustainable, long-term benefits to customers. In Part 3 – Long-Term Factors and Opportunity Assessment, Aether provided factors supporting long-term hedging. If future costs can be stabilized at levels attractive relative to historical costs, that would offer considerable customer benefit. And avoidance of future price volatility would be valuable. Therefore Aether examined market price context as well as long-term supply and demand factors.

From a pricing perspective, current natural gas prices are low relative to historical prices, low relative to global gas prices, and are forecasted to remain low relative to oil prices. When that occurs, there are economic drives that will likely support a rise in U.S. natural gas prices. With regard to supply analysis, natural gas production replacement has been positive in recent years but not robust. Producer margins have improved from their recent low levels in 2012 but still are not large. Furthermore, producers' capital investment in natural gas exploration and production is declining (this is visible in the historically low rig counts). Lastly, oil exploration and production is currently more profitable than natural gas exploration and production. While supply factors are not of immediate concern, prices will likely need to increase over time to encourage supply additions to keep pace with demand.

Forecasts indicate that the future natural gas market will be a demand-driven market, as opposed to the last few years when it has been a supply-driven market. On the demand side, the largest demand additions are anticipated to be in electric generation, domestic transportation fuel, and international export of U.S. LNG. The pacing and scale of this demand is hard to forecast, but most forecasts indicate significant demand growth. As a result of stringent EPA regulation[1] to

[1] This includes several forms of regulation: National Ambient Air Quality Standard, Mercury and Air Toxics Standard, Clean Air Mercury Rules, Clean Air Interstate Rules, and greenhouse gas regulation.

limit emissions from stationary sources, many power generation owners are predicted to close old, inefficient coal plants as opposed to investing new capital to comply with environmental regulation. Natural gas is often the lowest cost resource that offers operational flexibility and stability. Therefore, most electric generation forecasts reflect continued closure of coal plants and new capacity additions in gas generation and renewable energy.

Environmental regulation is also driving market changes with respect to natural gas as a transportation fuel. Currently, transportation demand for natural gas is a small portion of total U.S. gas demand. It is very hard to predict the future adoption rate of new technologies and the speed of commercialization with respect to natural gas vehicles. Natural gas vehicle conversions are more likely to occur when there are fuel savings by switching to gas, fueling infrastructure is available, and there is environmental regulation pushing the industry to change. While announcements of new investment in CNG and LNG technologies slowed when oil prices declined in 2014, it is surprising how many investments still moved forward. A number of companies in the marine, fleet, and rail sectors are investing in new equipment and fueling infrastructure. Aether's perspective is that since most natural gas price forecasts do not anticipate large growth in the natural gas vehicle space,, if this sector growth gained momentum, it would be a significant surprise in terms of market impact.

Next to electric generation demand for natural gas, US gas export is the next largest area of demand growth. In the global LNG market, large international demand increases and supply expansions are projected over time, although exact the pace and scale is unknown. There is production uncertainty among a number of the exporting countries, either because of natural gas supply uncertainty or political instability. Import demand projections are also uncertain, since demand increases depend upon a variety of factors such as the rate of economic growth, fuel switching from coal, the competitiveness of renewable and nuclear energy projects, and geopolitics. But U.S. LNG producers appear to be well-positioned for future gas exports, based upon a supportive regulatory approval process, low costs to build export capacity, short construction time for brownfield projects, evidence of long-term contracts, and the lowest cost origin gas. This portends large natural gas exports in the coming decades.

In Part 4 – Portfolio Modeling**,** Aether modeled BHUH's aggregated gas supply portfolio, showing the effect of hedging short-term versus hedging long-term gas. The objective was to compare and contrast the risks of hedging only short-term against the opportunity cost of hedging long-term. Aether tested the portfolio modeled with monthly granularity over a twenty year period with six different hedging scenarios. These included the following (graphs illustrating each hedging scenario are in Part 4- Portfolio Modeling):

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- Scenario 1 - Current Hedging Plan
- Scenario 2 - Current Hedging Plan and Gas Reserves starting at 18% in Year 1 and rising to 34% by Year 11
- Scenario 3 - Short-term, Medium-term and Gas Reserves 35% long-term
- Scenario 4 - Short-term, Medium-term and Gas Reserves 50% long-term
- Scenario 5 - Short-term, Medium-term and Gas Reserves 60% long-term
- Scenario 6 - Short-term, Medium-term and Gas Reserves 75% long-term

Aether examined the gas supply cost impact of the six different hedging scenarios given ten different market price scenarios. The beginning assumption was that short-term hedges (call options, futures, short-term fixed price and storage injection gas) were purchased at the Base Case Price scenario. The long-term hedges were acquired at an Illustrative Reserves Price scenario. The Illustrative Reserves Price scenario was a theoretical price provided by BHUH for purposes of illustrating the benefit of participating in cost of service gas program.

The ten price scenarios were an illustrative range of potential market price outcomes. The price scenarios were composed of eight price forecasts, the Base Case Price, and an Extreme High Price scenario. [redacted] The Extreme High was a price scenario that was two times the Base Case price scenario for 2017 forward. The graphical depiction of the Illustrative Reserves Price scenario and the ten price scenarios is provided below:

2 [redacted]

Figure 1 – Illustrative Reserves Price Scenario and the Ten Henry Hub Price Scenario

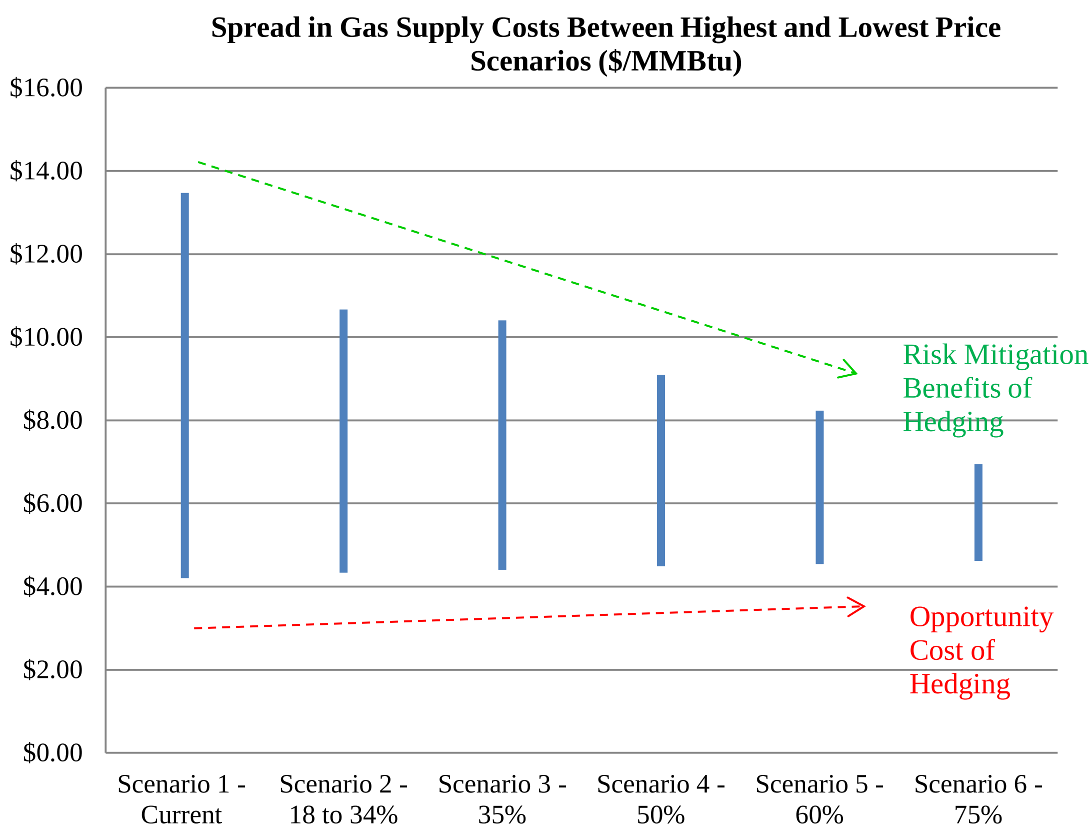
[redacted]

In nominal prices, the 2016 annual starting prices at Henry Hub for the ten price scenarios ranged from $2.40 / MMBtu to $4.05 / MMBtu. By the twentieth year of the forecast period, the difference between the forecasts expanded, ranging from $5.20 to $19.45 in 2035.

Aether compared the ten price scenarios to the assumed hedging cost, and looked at the impact with the six different hedging scenarios. The results from the portfolio modeling are shown in the figure below. The candlestick chart (vertical lines) depicts the range in gas supply costs for each hedging scenario. The higher the percentage hedged of the portfolio, the narrower the spread in gas supply costs across all the price scenarios. This illustrates that the higher the percentage hedged, the more stable customer gas supply costs.

The chart is also helpful for viewing the trade-off between price mitigation and potential opportunity cost. The green arrow directionally shows the price volatility mitigation achieved with greater percentages of hedging – the higher the hedging percentage, the greater the mitigation against the higher price scenarios. The red arrow directionally shows the potential opportunity cost of hedging greater percentages of the portfolio. Opportunity cost represents the difference between the hedged cost and lower market prices (represented by the lower price scenarios). The opportunity cost is much smaller than the potential risk mitigation achieved because the Illustrative Reserves Price scenario is a relatively low price. There is a small price differential between the Illustrative Reserves Price scenario and the lower price scenarios.

Figure 2 – Graphical and Tabular Results of the Portfolio Modeling (Average Cost)



[redacted]

The portfolio modeling used an illustrative reserves price to reflect the cost of gas production. Production was modeled as a fixed price commitment for a fixed volume, which is a conservative modeling approach. In a "drill to earn" structure, the initial volume of proved producing properties is set, but there is flexibility in the future to speed up or slow down incremental drilling. For example, if forward prices did not justify additional drilling, BHUH could decide not to invest additional capital in drilling and extraction.

In Part 5 – Conclusions and Recommendations, Aether found BHUH's hedging program objectives are clearly articulated and the hedging protocols are well understood. The hedging instruments are consistent with the hedging goals and managed carefully. Aether found the hedging goals were similar across BHUH's gas utilities, tailored slightly differently. Hedging is executed with a blend of storage, fixed price hedges, and call options hedges. Success is measured through effective execution of the program, providing price protection at a reasonable cost, and the ability to protect customers from price volatility.

Aether found BHUH's gas utilities' hedging program protects customers against seasonal price spikes. For the gas utilities, the hedging focus is on the upcoming one to two winters. While the current gas utilities' hedging program protects customers against short-term market risks, it does not protect customers from medium-term and long-term market price exposure. In contrast, BHUH's five year hedging program for its Colorado electric utility differs from that of the gas utilities because the hedging program begins at 50% hedging and declines to 10% by the last year. When a utility employs longer-term hedging, there is greater opportunity to hedge price exposure and stabilize rates going forward in time.

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Long-term market analysis points more to prices rising over time than falling. From a supply and demand perspective, current production trends may be insufficient to meet potential demand growth, creating uncertainty over the future direction of natural gas prices. Emerging supply and demand fundamentals appear to be changing, where gas prices may need to rise to spark more production to meet the projected future demand. Even though Lower 48 production increases are forecasted, decisions by large independent producers to reduce capital in gas production and in some cases, to shift from gas production investment to oil production, indicate gas production economics are not very attractive for producers at current gas prices. Canada does not offer the same low cost ample supply as it used to, as its exportable surplus continues to decline. From a demand perspective, there is new gas demand emerging from retirement of coal plants, domestic transportation demand for LNG and CNG, and North American exports pipeline gas to Mexico and LNG to other countries.

The summary table below aggregates the fundamental drivers supporting long-term hedging:

Figure 3 – Factors Supporting Long-Term Hedging

Customer Price	Gas production hedging can stabilize rates for customers at reasonable costs relative to historical costs
Historical Price Context	Recent historical low gas prices may not continue and may well revert to higher prices seen historically because of new gas demand
Crude Oil vs. Natural Gas	Despite lower crude oil prices, many producers still prioritize crude exploration and production over natural gas; U.S. LNG contracts may be shifting from a crude oil benchmark to blend of crude oil and natural gas benchmarks
Break-even Cost	Current market price is not much higher than the break-even cost of production for shale production
Gas Production Trends	Low producer profitability, shrinking capital investment in gas drilling and modest gas reserves replacement trends indicate prices may need to rise to encourage greater investment
Net Imports	Canada has less exportable surplus to send to the Lower 48 states and Mexican demand is forecasted to continue to grow
Transportation Demand	North American demand is growing through expanding CNG/LNG transportation demand
Environmental Regulation	Current and proposed regulation would result in still more gas generation and renewable energy additions
Comparative Pricing	Natural gas is attractively priced relative to other energy sources
U.S. Gas Prices	U.S. natural gas is attractively priced to destination LNG markets

LNG Plants	U.S. brownfield LNG export terminals have a cost advantage compared to greenfield plants elsewhere and a number of facilities have already received approvals
LNG Contracting	Most of the approved LNG export capacity has associated long-term contracts with large international LNG traders and consumers

Both the qualitative and quantitative analysis indicate that a higher percentage of hedging and hedging long-term would better achieve BHUH's objectives to provide rate stability and protect customers from market volatility. Therefore, in addition to having a short-term hedging program, Aether recommended that BHUH expand its hedging program to include long-term hedging to add more rate stability over multiple rate years. Long-term hedges should be considered when market conditions offer opportunities to hedge at attractive price levels and provide long-term rate stability for customers. An integrated approach incorporating short-term, medium-term and long-term hedging would meet the objectives of BHUH Gas Supply 1) provide reasonably priced natural gas; 2) provide a high level of reliability; and 3) mitigate price volatility. Long-term hedging would provide long-term rate stability and reliable supply for customers.

Aether's analysis of future supply and demand drivers supports long-term hedging. Given the market price analysis and shifting supply and demand factors, there are compelling reasons for BHUH to consider long-term hedging. There appears to be an opportunity to lock in long-term gas costs at relatively attractive price levels for customers. There are many indications U.S. natural gas prices will rise. Current natural gas prices are low relative to historical prices, but also compared to alternative fuel prices and global gas prices.

Additionally, Aether's stress-testing of the long-term gas supply portfolio in Part 4 – Portfolio Modeling supports long-term hedging. Greater upside price protection is achieved through a higher percentage of hedging. While there is no guarantee that prices will rise, the opportunity cost to hedge is the acquisition cost. Hedging protects against the risk of prices rising.

BHUH is exploring a strategy to invest in natural gas reserves to serve regulated customers. This is consistent with Aether's recommendation BHUH hedge further forward in time. The Cost of Service Gas proposal would add diversity to BHUH's gas supply portfolio while offering greater rate stability. Owning long-term gas production would allow BHUH to rely less upon the short-term market for gas supply, thereby also introducing more security of supply in its portfolio.

Today, on an annual basis, BHUH hedges 27% to 55% of its utilities' gas requirements using storage, short-term fixed price, and call options. Going forward, Aether recommended long-term hedging of a minimum of 35% with a target of up to 50% hedged with gas reserves, in combination with some short–term hedging. The range in percentage of gas reserves hedging among other utilities is quite varied– ranging from 15% by Sacramento Municipal District to 65% by Questar Gas. The "up to 50%" recommendation for reserves acquisition is based upon several factors. It takes a great deal of management time to execute and manage this effort, as well as Commission time to monitor and assess the results. A larger program will provide greater operating efficiencies and economies of scale. And the modeling demonstrated that hedging long-term with a higher percentage provides more rate stability and protection against rising prices.

While greater hedging such as 60% or 75% would provide even more stability in gas supply costs, there is a risk that, is such long-term hedges make up too large a percentage of the portfolio, there is less room for BHUH to use other tools available to it. A high percentage of long-term hedging leaves little room for future portfolio management flexibility or innovation in the future. For example the combination of 75% hedged and contracted storage would aggregate to close to 100% for the winter season, leaving no opportunity to use other tools such as call options.

There are two unique elements of BHUH's Cost of Service Gas proposal, compared to reserves acquisitions of other utilities. One, BHUH has an oil and gas exploration and production affiliate that can advise on key risks and opportunities. BHUH would benefit from the experience of its exploration and production affiliate that could advise on key issues and potentially act as the operator.

Two, BHUH is proposing a performance benchmark that should further reduce the risk for customers and align interests between customers and the shareholders. BHUH is proposing that its allowed ROE be decreased by 100 basis points if there is a Hedge Cost associated with the gas production, reducing opportunity cost risk for customers. Given BHUH's proposed authorized ROE is 9.86%, this would represent a potential penalty of more than 10% of its allowed ROE, which is not inconsequential from a percentage standpoint. The proposal has an upside incentive that allows for increasing the allowed ROE by 100 basis points if there is a Hedge Credit.

Aether proposed an integrated approach for BHUH to link together the short-term, medium-term and long-term hedging. The gas reserves would be the base of its hedging program, upon which short-term and medium-term hedges would be layered. BHUH would set hedging targets by year that combined reserves with short-term and medium-term hedges. The total hedged amount would be highest for the coming year, where there is more market volatility. Then the total hedged percentage would decline over time.

For example, in Year 1, BHUH would have short-term, medium-term and long-term hedges in place to aggregate to a target amount. The hedging amount for Year 2 would include short-term and long-term cost of service gas aggregating to a lower target than Year 1. The decline would similarly apply for Years 2-5 with medium-term hedges declining until Year 6 where the cost of service gas would be the only forward hedge. This would be done on a rolling basis, so that at any given point in time, BHUH's gas supply portfolio would have a consistent shape looking forward into the future. As one year rolled off, then new short-term and medium-term hedges would be executed to maintain the hedging plan targets.

The final part of Aether's recommendation was for BHUH to set a hedging band for the short-term and medium-term horizon. Hedges would be executed within the pre-determined range based upon changing market conditions. The range would be set with a minimum level and a maximum level by year, and BHUH would hedge between the minimum and maximum levels based upon forward fundamental and technical market analysis. It is advised BHUH retain decisional documentation to support decisions of where to hedge within the minimum and maximum targets.

The minimum target levels would include the reserves production and the storage plan. Maintenance of storage is justified because storage is a critical balancing tool necessary for system flexibility and meeting winter peaking load. BHUH would lease long-term storage capacity and summer purchases of gas for winter withdrawal would provide a seasonal short-term hedge. The maximum target would allow for additional use of call options and/or short-term fixed price contracts. After the gas reserves and the gas storage, the call options would be the next priority. This is because BHUH can use call options to insure against short-term price spikes during winter months. The lowest priority for additional short-term hedging up to the maximum amount would be short-term fixed price. This has a lower priority compared to storage and to call options since the gas reserves production performs as a long-term physical hedge. The graph below is a pictorial representation of how an integrated plan with hedging bands could be accomplished.

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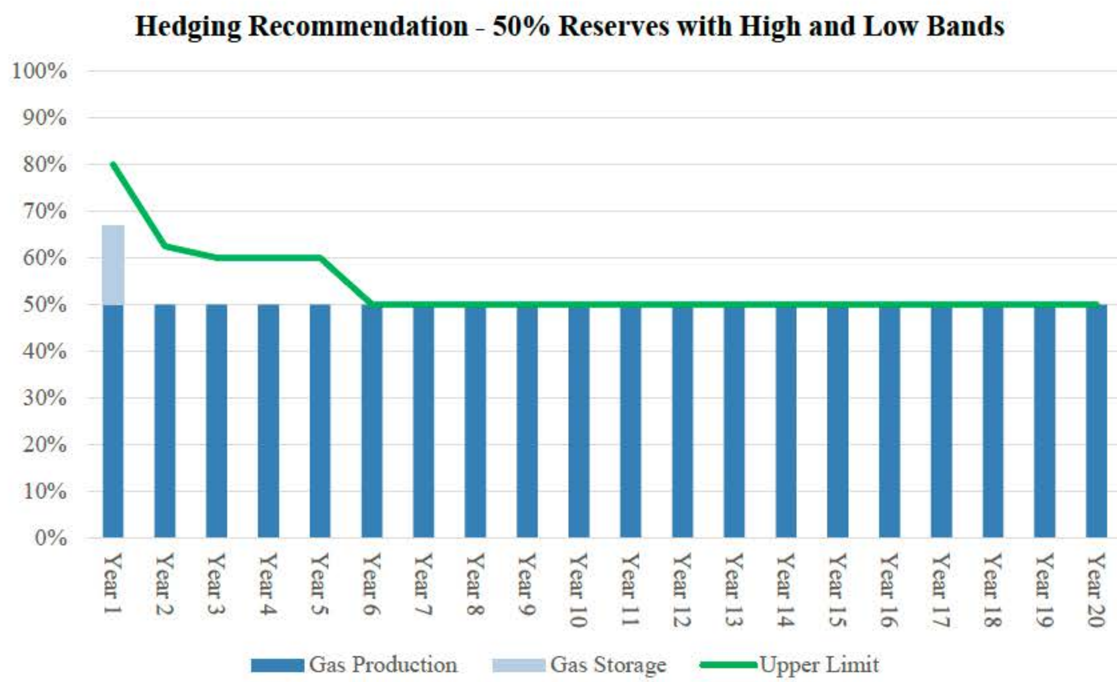
Figure 4 – Illustrative Integrated Short-Term, Medium-Term, and Long-Term Hedging Plan



The integrated short-term, medium-term and long-term hedging plan will change with gas production. With a reserves acquisition, BHUH would rely less on short-term and medium-term hedging. The graphs for Hedging Scenarios 1 through 3 in Part 4 – Portfolio Modeling help illustrate the type of changes that would occur in the short-term and medium-term hedging over time. As BHUH entered into new acquisitions, its gas and electric utilities could submit revised short-term and medium-term hedging plans to the Commission, illustrating how hedges for the next one to five years would be integrated with the natural gas production.

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Part 1 – Current Gas Supply Portfolio Review

Summary

In Part 1 – Current Gas Supply Portfolio Review, Aether reviewed BHUH's approach to hedging natural gas costs for customers. This included an analysis of the hedging program effectiveness with respect to consistency with gas supply planning. Aether reviewed hedging goals, risk management infrastructure, and hedging program design. Aether also reviewed BHUH's use of storage, physical contracts, and financial derivatives. To complete its review, Aether conducted interviews with Company representatives and reviewed documents such as hedging reports, gas supply plans, risk management policies and risk limits, internal gas supply planning documents, and presentations for internal and external parties. The background research is summarized in Appendix D – Document Review and Company Interviews.

Because there can be different hedging strategies for different time frames beyond the current Gas Supply Year, for purposes of this report, Aether delineated hedging time horizons as follows:

- Short-term hedging refers to hedging for the current Gas Supply Year and the upcoming Gas Supply Year (2 years and less)
- Medium-term hedging refers to hedging for Gas Supply Years 3-7
- Long-term hedging refers to the time horizon beyond Gas Supply Year 7

Aether found BHUH's Hedging Program to be cohesive and well structured. There is a clear understanding among company representatives of the hedging goals and guidelines. BHUH is well-positioned to continue hedging and to explore additional hedging opportunities beyond its current hedging horizon.

BHUH conducts natural gas hedging in all its gas utilities and one of its electric utilities. The hedges are passed through to utility customers at cost and are recovered either in purchased gas adjustment (PGAs) or an energy cost adjustment (ECA) mechanism. The design and tenor of the natural gas utilities' hedging programs are similar. There is some variation from state to state, with different weightings of instruments, but the focus on seasonal price volatility is consistent. The hedging for the gas utilities is short-term, focused on one to two winter seasons. BHUH uses natural gas storage, fixed price, and call options in its hedging program. The hedging programs are supported by the regulatory bodies.

BHUH has a different hedging program for its Colorado electric utility, hedging five years forward in time. In addition, BHUH uses only fixed price hedges for the electric utility. Its plan to hedge longer-term reduces potential risk exposure over multiple rate years, providing longer-term rate stability for customers.

Aether found BHUH's hedging for its gas utilities and its electric utilities to be very transparent. Aether's recommendations to expand BHUH's hedging program are provided in Part 5– Conclusions and Recommendations.

Purpose of Hedging

For purposes of this report, "hedging" refers to strategies utilities can use to provide rate stability and to reduce the risk of rising natural gas rates for BHUH's customers. Utility hedging is not speculative and does not add risk exposures to a gas supply portfolio. Instead, hedging is the act of reducing risk exposure in a portfolio, and is not related to profit and gain or trying to "beat the market". The act of locking into a price means the utility has accepted that price and is willing to forego further opportunity in exchange for protecting against prices moving disadvantageously.

A gas or electric utility is a net buyer of natural gas and procures gas supply to reliably meet customers' needs. Natural gas customers use natural gas for heating, cooling, cooking, water heating, and manufacturing processes. A gas utility has the obligation to serve gas customers with either gas supply or gas transportation service. Typically only the largest customers procure their own gas supply and take transportation service. Most gas customers (chiefly residential and commercial customers) rely upon the utility to purchase gas supply to meet their needs. The cost of the gas supply is passed through at a tariff rate reflecting the utility's cost to acquire the gas. The utility's purchasing practices and the direction of the wholesale natural gas market price affect the customers' cost of gas supply. If a utility purchases in the spot market (representing one day to one month forward in time), customers will bear the cost of whatever the spot wholesale market price is at that particular time. If the gas utility can manage the gas supply costs, there is less rate uncertainty for customers. If natural gas prices increase, customers benefit from the utility hedging gas supply costs at lower prices.

Electric customers do not use natural gas directly, but natural gas is a generating fuel for natural gas-fired power plants, from which they receive power. For its electric utilities, BHUH has generation that requires natural gas as a fuel source. Similar to the way BHUH can manage gas supply costs for natural gas utility customers of Black Hills' various operating gas utilities, BHUH can manage gas fuel costs for electric customers of Black Hills' various operating electric utilities. It can provide greater rate stability to electric customers when it can manage the natural gas fuel cost risk. If natural gas prices increase, customers benefit from the utility hedging gas fuel costs at lower prices.

In recent years, some utility commissions and utility boards have asked, “why hedge?” given the downward trend in market prices from 2009. Aether advises utilities and regulators that the reasons to hedge are:

- The decision not to hedge means the utility is speculating with its net short position.
- Customers do not like rate surprises and want to be able to budget for energy costs.
- Utilities face rising costs in many areas, so why not manage costs that can be managed?
- There has been a long trend of declining energy prices since 2009 which began to turn around in 2013.

Some commissions have told utilities to reduce their hedging programs because the opportunity cost in recent years exceeded opportunity costs in prior years. But this determination has been made with little consideration of the risk to customers. Reduced hedging has less “cost” in declining markets, but the choice to scale back the hedging is making a bet on the direction of prices. Also, a decision to reduce a program without a quantitative assessment of potential risk exposure to customers, fails to protect customers’ interests. While reducing a hedging program might have resulted in lower rates through 2012, the decision was often made without consideration to the impact on customers had the market moved up, instead of down. Deciding not to hedge when prices are low will not provide much opportunity and poses significant risks.

Hedging Goals

Hedging goals shape a utility’s hedging strategies. Based upon hedging goals, the utility can determine what types of hedging instruments would best fit the portfolio. The hedging goals should take into account an organization’s capacity to hedge, considering financial constraints, counterparty arrangements, market liquidity, and operational constraints.

In an excerpt from its annual Gas Supply Plan filed with the Kansas Corporation Commission, BHUH describes its three primary goals in its gas supply practices: 1) provide reasonably priced natural gas; 2) provide a high level of reliability; and 3) mitigate price volatility. These three goals are the same in its other state filings. In this manner, BHUH combines price management with mitigating price volatility. In addition the hedging objective of mitigating price volatility is closely interwoven with an operational commitment to a high level of reliability and an overall focus on managing natural gas supply costs.

The focus on physical operations and reliability are addressed in BHUH's Gas Supply Plans. In addition to physical supply risk management, there are risks associated with the price or cost of natural gas, which is the focus of this report. In the excerpted text above, cost and reliability are the core objectives to hedging price risk for customers. To "provide reasonably priced natural gas" is an objective to manage costs with a diversified portfolio approach of gas supply options for a defined time horizon. This objective and the objective to mitigate price volatility can be met through hedging.

Hedging Program Design

Aether reviewed BHUH's hedging program design to understand how BHUH approaches hedging and mitigates risks. Aether looked at the hedging time horizon to review how far forward BHUH hedges and examined the percentage hedged by year to understand the size and scale of the hedging program. Aether reviewed the hedging protocols to understand how BHUH executed its hedges. Aether also reviewed the instruments used to mitigate price risk.

Aether noted that BHUH's hedging program design for the utilities are consistent with BHUH's overall hedging objective, but are tailored to fit the hedging program design for each jurisdiction. The amount of supply required to meet load is defined by load forecasts, and the percentage to be hedged relates to the forecasted load requirements. BHUH serves 763,000 regulated natural gas and electric customers in seven states: South Dakota, Nebraska, Iowa, Kansas, Colorado, Wyoming and Montana. Figure 5 below shows the organizational chart of the subsidiaries. The entities in the blue rectangles are the regulated utilities:

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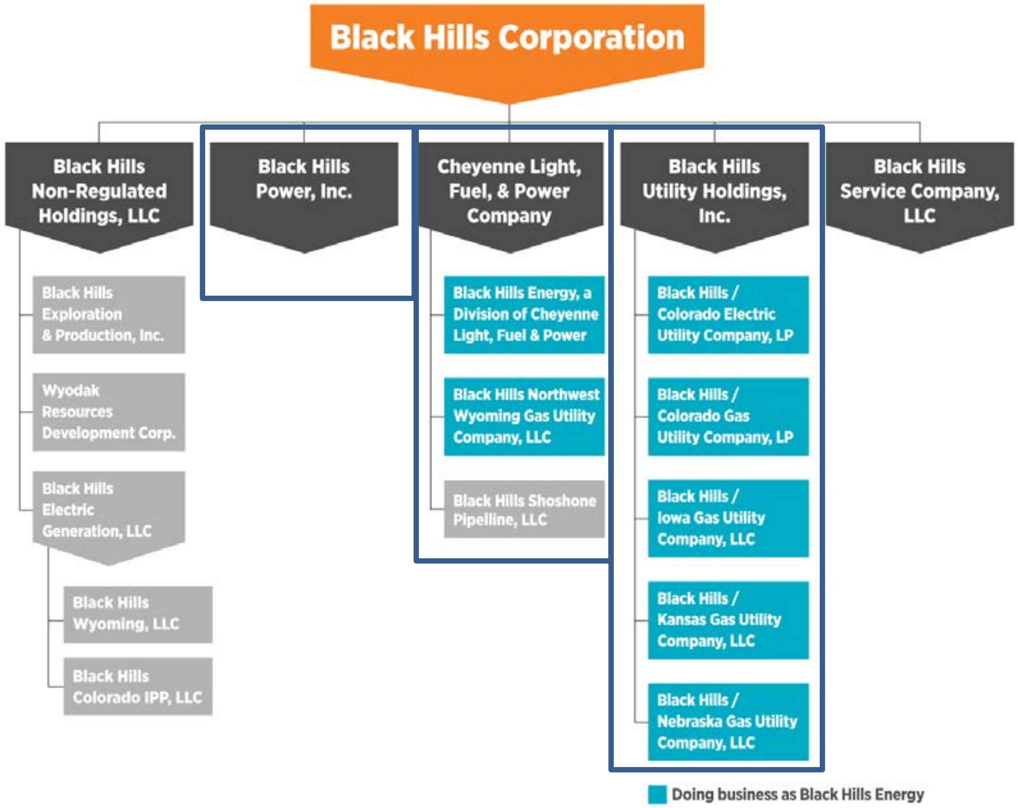
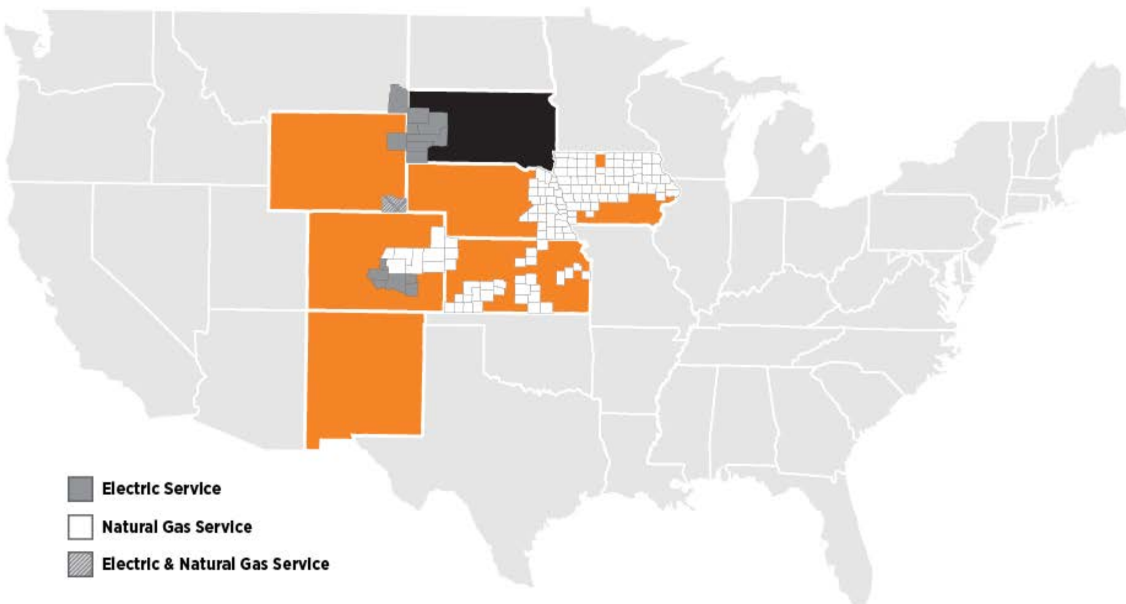
Figure 5 – Black Hills Corporate Structure



Black Hills Power Inc. serves approximately 70,000 electric customers in 20 different communities throughout western South Dakota, northern Wyoming, and southeastern Montana. Cheyenne Light, Fuel & Power provides electric and natural gas service to nearly 40,000 customers in or near Wyoming's capital city, Cheyenne. Black Hills Energy provides electric and natural gas service to more than 600,000 customers in hundreds of communities throughout Colorado, Iowa, Kansas and Nebraska. Black Hills' geographical service territory is depicted in the map below:

Figure 6 – Black Hills Service Territory[3]



The gas supply function for all utilities requiring gas supply is aggregated under the management of one team, providing consistency in procurement and hedging practices and economies of scale. BHUH hedges for the short-term on the upcoming Gas Supply Year, with particular focus on the winter months where loads are greatest and price volatility is most extreme. Below is a summary table outlining the hedging program design by utility:

Figure 7 – Hedging Program Design by Utility

State	Tenor	Hedging Instruments
Colorado (Gas)	1 Winter	Storage, Futures, Call Options
Colorado (Electric	5 Years	Fixed Price Physical
Iowa	2 Winters	Storage, Futures, Call Options
Kansas	1 Winter	Storage, Call Options
Montana		No gas hedging
Nebraska (Gas)	2 Winters	Storage, Futures, Call Options
Nebraska "Annual Price Option"	1 Year	1 Year Fixed Price Supply contract

[3] The map does not reflect the recently acquired NW Wyoming territory.

State	Tenor	Hedging Instruments
Wyoming (CFL&P)	1 Winter	Storage, Fixed Price Physical
Wyoming/SD (Electric)		No gas hedging

The major market pipelines at which BHUH purchases gas supply include:

Figure 8 – Pipelines Serving Black Hills' Utilities That Hedge Natural Gas

State	Pipelines Serving Black Hills' Utility Companies
Colorado	CIG
Iowa	NGPL, NNG
Kansas	NNG, Southern Star, Enable, Tallgrass
Nebraska	NGPL, NNG, Tallgrass
Wyoming	CIG

Additionally, the utilities lease gas storage capacity from the following pipelines: Northern Natural Gas Pipeline (NNG), Natural Gas Pipeline (NGPL), Colorado Interstate Gas (CIG), Southern Star (S Star), and Tallgrass Interstate Gas Transmission (TIGT).

Risks Mitigated

Aether assessed BHUH's hedging program from a variety of risk exposures including market price risk, locational price risk, load uncertainty, and credit risk. Aether determined BHUH managed market price risk, load variability, and credit risk consistent with utility industry practices.

- **Market Price Risk** – In addition to its physical operational supply planning, BHUH examines risks associated with rising natural gas. BHUH hedges against the absolute level of gas prices rising in its short-term hedging time-frame through a variety of strategies: 1) fixed price physical, 2) futures contracts, and 3) call options. Through these strategies, BHUH mitigates some of the upside price risk exposure, protecting customers against sharply increasing gas supply cost.

- **Locational price risk –** Locational price risk (also referred to as "basis" risk) represents the risk inherent in a gas supply portfolio when a hedge is located in a different location from where the supply is needed. For example, if a utility hedges at an alternative location than at its receipt points, there is basis risk. Aether noted BHUH hedges fixed price risk through Henry Hub futures and physical fixed price contracts. BHUH monitors the basis risk and at times enters into basis swaps when there are offers in the market.

- **Load variability** – Because of weather uncertainty and associated volumetric variability risk. BHUH uses storage inventory to supplement pipeline-delivered supply to help meet gas customers' requirements throughout winter. It leases natural gas storage from several pipeline companies, which allows BHUH to hedge seasonal supply cost risks, taking advantage of injecting lower cost summer gas for winter withdrawal when prices are higher. Storage helps the gas utilities manage supply reliability throughout the winter season and protect customers from extreme spot market price volatility.

  BHUH has a storage policy to withdraw gas during the winter season to ensure adequate supplies through the winter delivery period. When spot prices are higher than the weighted average cost of gas in storage (plus transportation and carrying costs), it will withdraw from storage as opposed to purchasing spot supply, up to the monthly limits. This helps protect customers from daily market volatility.

- **Credit risk** – A utility's hedging program must be sized appropriately for the organization's capacity to hedge (ex: financial constraints, counterparty arrangements, and market liquidity). BHUH has more than adequate credit capacity given the current program design and market conditions. BHUH manages counterparty non-performance risk and credit default risk through a credit risk policy and counterparty credit limits. There are master agreements with physical counterparties and enabling agreements and credit thresholds negotiated with financial counterparties. It manages its exchange-based futures and call options through a Futures Commission Merchant (FCM). BHUH also tracks counterparty collateral and estimates potential collateral it may need to post.

Time-Frame and Volume % Hedged

A utility has two 'levers' to manage the scale of hedging in a hedging program: the hedging program time horizon and the percent of the portfolio hedged. There is no one standard practice with respect to time horizon and volume percent hedged. Utilities hedge over a variety of time frames, ranging from 25% to 90% in the short-term and 0% to 65% in the long-term. Utilities all place greatest emphasis on the season when price volatility and load requirements are greatest. Most utilities additionally hedge in the off-season to provide a known acquisition price for storage and to provide rate stability from one rate year to another. And the percentage of the portfolio that is hedged increases the closer in time to the delivery period.

Aether found BHUH's hedging program design to be consistent with its hedging goals. BHUH's hedging program design is consistent with utility industry practices to hedge against price spikes and to smooth rate volatility for customers. BHUH's hedging program has clearly articulated percentages of the amount of the portfolio to be hedged for the upcoming winter heating season (and the second heating seasons for some of its utilities). And hedging is executed over a staged period of dates in accordance with a dollar cost averaging strategy. For short-term hedging, the hedging dates occur at set intervals. For long-term hedging at its Colorado electric utility, the hedging takes place ratably over a longer term horizon. The figure below illustrates the staging of hedging over the five year horizon for the Colorado electric utility:

Figure 9 – Five Year Hedging Plan

Annual Hedges - 5 Year Strategy	2015	2016	2017	2018	2019	2020
2011	10%					
2012	10%	10%				
2013	10%	10%	10%			
2014	10%	10%	10%	10%		
2015	10%	10%	10%	10%	10%	
2016		10%	10%	10%	10%	10%
2017			10%	10%	10%	10%
2018				10%	10%	10%
2019					10%	10%
2020						10%
	50%	50%	50%	50%	50%	50%

For example, in 2015, the maximum target amount (in this case 50%) is hedged, but the percentage hedged in the forward years is less (40% for 2016, 30% in 2017, 20% in 2019, and 10% in 2020). Stair-stepped hedging of declining percentages going forward in time is consistent with most utilities' hedging practices.

A hedging program over multiple years narrows the range that gas supply costs can change from one rate year to another. The benefit of layering hedges over multiple years is that it connects rate years, so that the subsequent rate year relates to the previous rate year, as a portion of its hedges are executed at the same time. In this way, the subsequent rate years are less likely to diverge materially from the previous rate year. This provides continuity in customer rate path from one rate year to the next.

But outside of the Colorado electric utility gas supply, BHUH's utilities' hedging is on a short-term basis of one to two winter seasons, thereby limiting BHUH's ability to manage commodity costs for its utilities' customers over multiple rate years. If BHUH entered into longer-term

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hedging, the commodity cost of gas would be smoother over time, offering more rate stability for its utilities' customers.

Hedging Protocols

Many utilities employ hedging protocols where specific volumes are executed on pre-determined dates, so that hedges are executed ratably until the delivery month. This is sometimes referred to as "dollar cost averaging" and the intent is to average hedge costs over a period of time. The hedging protocols are called "programmatic" when the hedging data and hedging volumes are set.

BHUH employs slightly different hedging protocols depending upon the jurisdiction. In all the jurisdictions there are programmatic elements. For example, BHUH sets targets to hedge certain volumes within a specific timeframe, which is a programmatic element. In several states (Iowa and Nebraska), BHUH exercises some discretion in hedging, executing the hedges within a range of dates. In other states (Colorado and Kansas), there are a defined dates when BHUH must execute hedges.

Figure 10 – Hedging Protocols by State

State	Hedging Protocols
Colorado (Gas)	Programmatic
Colorado (Electric)	Blend of Programmatic and Discretionary
Iowa	Blend of Programmatic and Discretionary
Kansas	Programmatic
Nebraska (Gas)	Blend of Programmatic and Discretionary
Nebraska "Annual Price Option"	Programmatic
Wyoming (CFP&L)	Programmatic

A blended programmatic and discretionary approach allows a utility to hedge within boundaries, leveraging its staff's professional judgement and industry expertise. Transparency and clearly-defined procedures for discretionary hedging are important. Aether found BHUH's discretionary hedging for its Nebraska and Iowa gas utilities to be well-managed. Because there is a defined time horizon and volume, the hedging is completed by the end of the period. When applying discretion about when to execute purchases within the defined hedging window, BHUH takes into account fundamental market factors. And BHUH uses technical market analysis to help decide when to execute hedging transactions within the hedging window. It uses stochastic analysis to estimate when the market appears to be overbought (likely to fall as buyers seek to sell their long positions) or oversold (likely to move up as sellers seek to purchase their short positions). For example, BHUH looks at 22-day and 40-day moving averages to examine market trends.

Additionally, BHUH keeps records of hedging decisions and a management team meets quarterly to review hedging results. The portfolio update alerts the management group to what has been hedged and how this relates to the approved hedge plans. The portfolio update also highlights market trends that might impact future hedging and/or affect BHUH's counterparties. Lastly, the portfolio update reports the financial gain or loss on the hedging instruments which is required for financial reporting.

Hedging Instruments Employed

Consistent with many other natural gas and electric utilities, BHUH uses a portfolio of contracts to manage physical supply risk and price risk. BHUH contracts with producers, aggregators, and marketers for physical supply priced at a market benchmark index. Most supply is priced at a monthly index, and some spot market supplies are purchased at daily indices.

To manage price risk, BHUH uses a combination of physical supply contracts and financial instruments. BHUH manages market price exposure one to two winters into the future, using storage, fixed price, and call options. It purchases gas supply at index prices during the off-peak months for injection into storage for winter withdrawal. With respect to fixed price hedging, in some cases BHUH purchases fixed price physical supply. But most of the fixed price hedging is typically executed with exchange-traded Henry Hub futures contracts. BHUH also hedges with exchange-traded Henry Hub call options to hedge price risk. Below is a table summarizing the hedging instruments utilized by BHUH by region:

Figure 11 – Hedging Plan Summary by State

State	Hedging Instruments
Colorado (Gas)	One winter - 8% storage, 33% monthly index, 26% futures, and 33% call options (67% hedged forward) Annual - 5% storage, 57% monthly index, 17% futures, and 21% call options (43% hedged forward)
Colorado (Electric	50% fixed price Year 1, 40% Year 2, 30% Year 3, 20% Year 2 and 10% Year 1

	Annual - 50% fixed price Year 1, 40% Year 2, 30% Year 3, 20% Year 2 and 10% Year 1
Iowa (Gas)	Two winters - 42% storage, 27.5% monthly index physical, 15% futures and 15% call options (72% hedged forward) Annual - 32% storage, 45% monthly index physical, 11% futures and 11% call options (55% hedged forward)
Kansas	One winter - 22% storage, 45% monthly index physical, 0% futures, and 33% call options (55% hedged forward) Annual - 13% storage, 68% monthly index physical, 0% futures, and 19% call options (32% hedged forward)
Nebraska (Gas)	Two winters - 42% storage, 27.5% monthly index physical, 15% futures and 15% call options (72% hedged forward) Annual - 32% storage, 45% monthly index physical, 11% futures and 11% call options (55% hedged forward)
Nebraska outstate (Gas)	Two winters - 31% storage, 39% monthly index physical, 15% futures and 15% call options (61% hedged forward) Annual - 22% storage, 57% monthly index physical, 11% futures and 10% call options (43% hedged forward)
Nebraska "Annual Price Option"	100% fixed price Annual - 100% fixed price
Wyoming Gas	One winter - 18% storage, 54.5% monthly index physical, 27.5% physical fixed price (46% hedged forward) Annual - 11% storage, 73% monthly index physical, 16% physical fixed price (27% hedged forward)

On an annual basis BHUH hedges 27% to 55% of the expected gas demand. For its gas utilities in Iowa and Nebraska, BHUH also hedges forward a second winter season. And for its Colorado Electric utility it has a five-year fixed price hedging plan that begins at 50% and declines to 10%

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by the fifth year. The actual mix of instruments for each utility differs by state. For the gas utilities, BHUH uses a diversified approach with several instruments, and for the electric utilities it hedges with fixed price instruments. Once hedges are executed, BHUH leaves them in place as opposed to liquidating them when they move advantageously, which is consistent with utility industry practices.

With the physical fixed price transactions, BHUH and the counterparty agree to a fixed price, where BHUH is the buyer and the counterparty is the seller. When BHUH hedges fixed price with futures, it is locking in a fixed price at Henry Hub, Louisiana, a major North American benchmark location. It places an order with its Futures Commission Merchant (FCM) to execute a transaction on the Chicago Mercantile Exchange (CME). BHUH's purchase is matched with another party's sale of futures. The transaction is subsequently cleared so that the CME becomes the counterparty to BHUH's transaction. The financial gain and loss from the futures position is maintained in an account with the FCM. BHUH provides initial and maintenance margin to the FCM to financially back the transaction for negative mark to market. BHUH allocates the futures hedges to the respective utility portfolios.

BHUH forward buys the futures contracts in accordance with its hedging plan and holds the futures contracts until right before the delivery month. At that point it sells the futures contracts and enters into physical purchases at the prevailing spot market price. In this respect the futures serve as a hedge until BHUH buys the physical gas. As a result, BHUH never takes physical delivery of gas at Henry Hub, but uses the futures contracts as a proxy hedge for gas supply it will purchase for its utilities.

BHUH takes a similar approach with exchange-based call options. The call options relate to the monthly futures prices that also trade on the exchange. Similar to the manner in which it transacts futures, BHUH purchases at-the-money call options on the CME exchange using its FCM. The call options are cleared through the exchange and the call options are held in an account with the FCM.

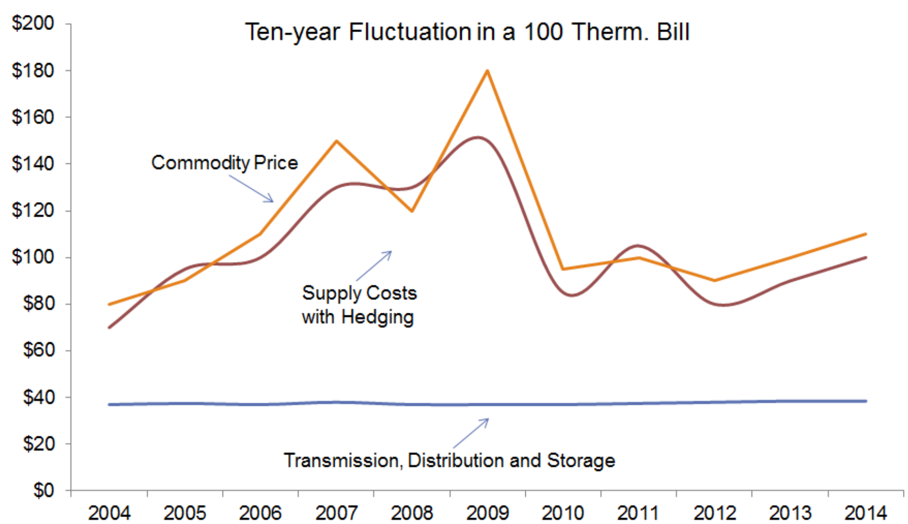
For each utility for which it hedges with options, BHUH has an options budget that is approved by the state regulators. BHUH acquires call options consistent with these budgets. If the budget available exceeds the cost of the target options, BHUH does not use the full budget. As with the futures hedges, BHUH allocates the call options hedges to the respective utility portfolios.

The following section, Part 2 – Gas Supply Hedging Options, provides a description of these standard hedging instruments and an explanation of how these can be used to implement different hedging strategies.

Measuring Success

BHUH assesses the success of its hedging program in several ways. Precise execution of the hedging plan is an important measure of success. In this regard, BHUH carefully monitors the hedges as they are executed and tracks the financial impact. A second measure of success is when BHUH can combine the affordability goal and the hedging objective, to protect customers against price volatility at a reasonable cost. To this end, BHUH monitors the costs of the hedging in the context of the overall commodity cost. As an example, the graph below shows the impact of hedging for Nebraska gas customers:[4]

Figure 12 – Customer Price Volatility[5]



The hedging graph above demonstrates how BHUH's hedging has reduced gas price volatility for customers relative to wholesale market prices. The third measure of success is that the hedging program meets the regulators' policy objectives.

[4] BHUH has represented the results would be similar for Iowa, Kansas, Colorado, and Wyoming customers
[5] *Black Hills Corporation, Natural Gas Supply Update*, Company presentation to Nebraska Public Service Commission, January 2014.

Overview of the Cost of Service Gas Proposal

BHUH is exploring a strategy to invest in natural gas reserves on behalf of regulated customers. The cost of gas service model is not new; other utilities have acquired gas producing properties as a regulatory asset and used proceeds from the sale of the gas production to offset the cost of gas supply for regulated customers. BHUH has an advantage compared to most utilities that have executed this plan or are considering it, for it has an exploration and production affiliate that can provide guidance during the acquisition process and potentially assist in the development and operating stages. Black Hills Corp E&P has experience drilling and producing gas in nine Western states in both conventional and shale gas formations. Its experience with planning, permitting, lifting costs, field services, and community relations will help BHUH identify appropriate locations that fit the regulated utilities' investment criteria. In this manner, the exploration and production company can lend significant expertise and help the regulated utilities understand potential risks and opportunities from the onset of the plan through the life of the wells' production.

Further, BHUH has proposed a plan to align shareholder interests with customer interests by introducing a performance metric in its Cost of Gas Service proposal. BHUH is proposing that its allowed ROE be decreased by 100 basis points if there is Hedge Cost associated with the production, thereby placing risk on BHUH and decreasing costs for customers. The proposal offers an incentive on the other side by increasing the allowed ROE by 100 basis points if there is a Hedge Credit.

The Cost of Service Gas proposal is consistent with BHUH approach to have supply diversity in its portfolio and to offer rate stability to customers. If BHUH can acquire gas production cost effectively, there is less uncertainty about future gas supply costs. An acquisition would mean BHUH would have less exposure to short-term prices, for the gas production volumes would hedge price exposure associated with utility gas purchases. The benefits of gas production versus contracting for gas are described in more detail in <u>Part 2 – Gas Supply Hedging Options</u>.

A gas reserve investment is a material undertaking from a resource and cost perspective. It is a commitment to lock in supply and cost for a long period of time. Therefore, it is important that the investment makes sense as a risk reduction strategy in addition to a security of supply strategy. Analysis of the relative price value and the impact of the natural gas supply and demand drivers are included in <u>Part 3 – Long-Term Factors and Opportunity Assessment</u>.

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Part 2 – Gas Supply Hedging Options

Summary

There is no one single model for utility natural gas hedging. Typically, the hedging strategy is a joint decision by the utility company and key stakeholders, and approved by the state commission. Consistent with the hedging goals, the hedging program is then defined by the amount of the gas supply that will be hedged, the time horizon of the hedges, and the hedging protocols addressing the mechanics of the hedging. Utilities have access to several risk management tools that can be used to reduce customer rate volatility and mitigate risk of increasing gas costs. Each tool has different uses, so a portfolio of tools is ideal for achieving hedging goals. Figure 13 below summarizes different tools' ability to smooth rate volatility and to mitigate price risk across different time horizons.

Figure 13 – Tools to Smooth Rate Volatility and Mitigate Price Risk

Risk Management Tool	Smooth Rate Volatility	Mitigate Risk of Rising Costs	Time-frame
Rate Mechanism	**Yes**	**No**	**Monthly to 1 year**
Storage	**Yes**	**Yes**	**Upcoming winter**
Physical Fixed Price	**Yes**	**Yes**	**1 month to 10 years**
Financial Instrument	**Yes**	**Yes**	**1 month to 10 years**
Volumetric Production Payment	**Yes**	**Yes**	**Up to 15-20 years**
Reserves Investment	**Yes**	**Yes**	**Up to 30 years**

The size and scale of a utility hedging program should be driven by what type of risk the utility wants to mitigate within its supply portfolio. Typically utilities design their hedging programs to meet one or more of the following objectives:

- Fix (lock in) customer rates
- Keep rates within a band
- Protect against price spikes

The three objectives above are separate mitigation strategies to address the risks of rising market prices and there are subtle differences between them that drive different hedging strategies and hedging program design. For example, if the objective were to fix customer rates, the utility would lock in the gas supply costs for customers by hedging a very high percentage of the portfolio with fixed price contracts. If a utility were comfortable with a wider band for customer rates, the utility could employ a lower hedging percentage and hedge with a wider variety of instruments. For example, a utility might use a no cost collar to put a band around gas costs. To protect against price spikes, a utility could purchase insurance, such as out-of-the-money call options. These hedging instruments are described in more detail below.

There are multiple hedging instruments and the protection each offers is contingent upon what occurs in the market. The hedging objective and the anticipated market price trend determine which instrument the utility will select. The hedging instrument selection is also affected by the availability and cost of the hedging instruments.

BHUH's goals to provide rate stability and protect customers from market volatility should drive the selection of hedging instrument, the scale of hedging, and the hedging time horizon. The current mix of tools for the gas utilities has been effective for protecting against seasonal price spikes in the short-term. Continued use of these instruments and potentially others are appropriate for short-term portfolio management. The use of longer-term hedging instruments would provide additional rate stability and protect customers from market volatility over an extended period of time.

Rate Mechanisms

Utilities use a number of rate mechanisms to provide customers with rate stability. One tool to spread out costs for customers is levelized billing or budget billing. Another tool is to recover differences between actual costs and billed costs from customers in a subsequent time period in a deferral account. The longer the deferral account amortization period, the more rate 'smoothing' occurs. Some utilities use cost deferral mechanisms to smooth that recovery over time. Rate mechanisms do not eliminate customers' exposure to rising commodity costs. Only through hedging can a utility reduce the likelihood of raising rates as a result of increasing natural gas market prices.

BHUH's Purchased Gas Cost Adjustment (PGA) is a gas cost recovery mechanism that allows the gas utilities to recover natural gas costs. Similarly, the electric utilities have an ECA (Energy Cost Adjustment) to pass through purchased power and fuel costs to electric customers. There is an associated deferral account that tracks the difference between actual costs and the estimated costs submitted in the annual PGA and ECA filings. Except for the Colorado gas utility and the newly acquired gas utility areas in NW and NE Wyoming, the PGAs are updated monthly.[6] In this respect, the utilities' customers see the effect of wholesale gas and power price volatility relatively quickly. Rate stability for customers comes from the use of storage and hedging instruments.

Gas Storage

Natural gas storage is a physical hedge commonly used by natural gas utility companies. Natural gas is injected during lower-priced spring and summer months and then withdrawn during periods of high prices, typically November through March. Utilities plan withdrawals to insure adequate supply during the peak winter period.

The most common form of underground storage is a depleted natural gas reservoir where useable natural gas is depleted and the field can be developed for storage. Given the depleted reservoir has previously held natural gas, it can be retrofitted and refilled by injecting natural gas. A second underground storage structure is a salt-dome cavern, which is flushed with water to create a storage cavern. A third form of underground natural gas storage is an aquifer, which is a water reservoir converted to gas storage. Aquifers typically require more cushion gas and are more expensive to operate.[7]

Another form of natural gas storage is LNG storage tanks. These require less space than underground storage and are typically located near concentrated load areas or where there are distribution system constraints. However, LNG storage costs are higher than traditional underground storage since the natural gas must be reduced to very cold temperatures to liquefy the natural gas. As a result, LNG is usually used as a "needle-peaking" resource for extreme peak needs, and typically represents a small portion of a utility's total storage capacity. Emerging demand for LNG as a transportation fuel may drive down the cost of LNG storage in the future. With a larger demand base, new LNG storage may become more modular in design and fabricated on a larger scale and distributed more widely.

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[6] The PGAs in Colorado, Northwest Wyoming (Black Hills Northwest Wyoming Gas Utility LLC) and northeast Wyoming (Black Hills Energy Northeast Wyoming Gas Utility LLC are updated annually.
[7] Energy Information Administration, *The Basics of Underground Natural Gas Storage*, August 2004, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html (accessed: January 2014)

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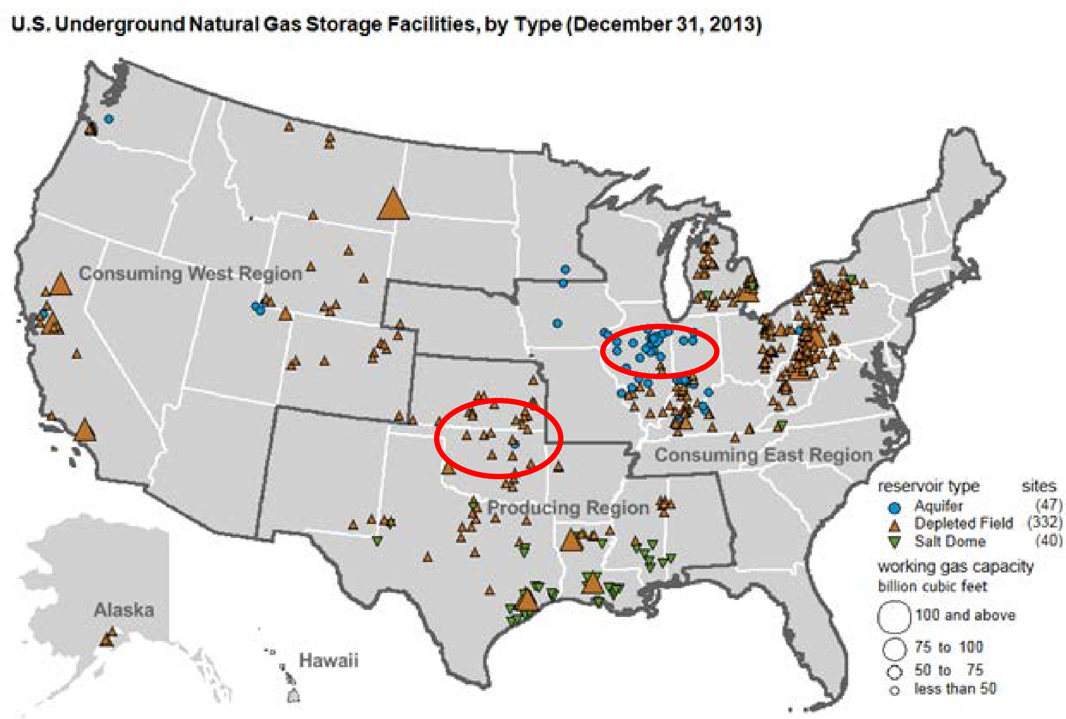
Natural gas storage is often leased by a utility to assure secure supply during peak demand periods to meet core customer demand. It is highly effective in meeting peak load demands during periods of cold weather, where customers would otherwise be more exposed to sharp increases in spot prices. Therefore, storage as a hedging tool mitigates extreme winter peaks during the heating season for the utilities' customers, but in a relative sense. The cost of storage is the purchase price of gas to be injected (acquired during the low demand months prior to the winter period), plus the cost of injection, the storage rate, withdrawal costs, carrying costs for the months when it is held as inventory, and sometimes transportation costs in and out of the storage facility.

As a result, the price of storage will reflect the trending annual market. During times of rising natural gas prices (example 2003 to 2009), the storage price of gas was higher than in declining markets (example 2010 to 2014). As a hedging tool, storage typically only serves as a short-term hedge, as summer injection gas is usually carried into the following winter. Below is a map of US storage facilities. BHUH's gas utilities lease storage from interstate pipeline operators in the Mid-Continent and the Midwest (circled in red):

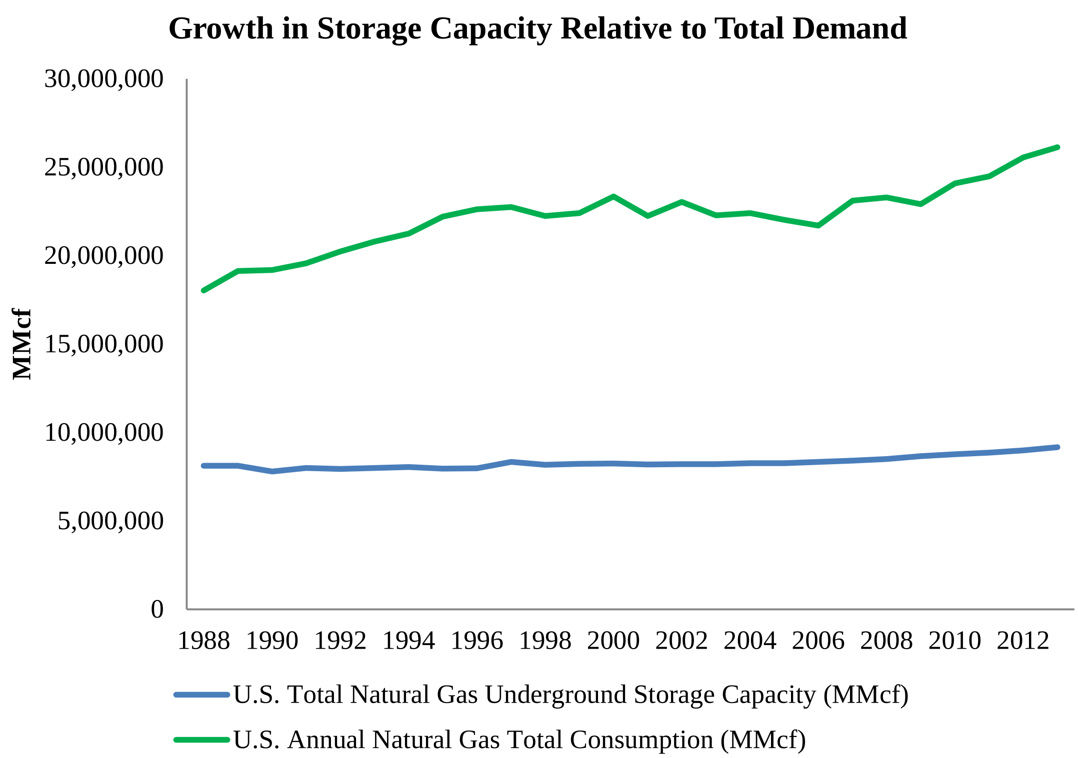
Figure 14 – U.S. Underground Storage (Source: EIA)



Because natural gas demand is highly seasonal as a result of heating demand, gas utilities will typically use storage to meet peak load requirements. With respect to alternatives, incremental storage may be less expensive than year-round pipeline transportation capacity that might only be used in winter and then under-utilized the balance of the year.

U.S. natural gas storage capacity has not been growing at the same rate as U.S. natural gas demand. Below is a graph illustrating the slower growth in total gas storage capacity (working gas and base gas capacity from 1988 to 2013):

Figure 15 – Growth in U.S. Natural Gas Underground Storage and Consumption Since 1988



A review of FERC-approved storage projects since 2000 for expansion of or new capacity indicates that very little new storage capacity is being constructed. Since 2011, FERC approved new projects totaling 393 Bcf of working gas capacity (compared to a 2013 U.S. total working gas capacity of 4,749 Bcf), which would represent an 8% increase in total capacity if constructed. But of the approved projects not yet in service, only 59.5 Bcf are under construction (representing a little over 1% additional capacity). Two storage projects totaling 35.7 Bcf have been put on hold and there are 297.4 Bcf of projects with no status reported.[8]

[8] Federal Energy Regulatory Commission, *Certificated Storage Projects Since 2000 For Expansion Of New Capacity, June 1, 2015*, http://www.ferc.gov/industries/gas/indus-act/storage/certificated.pdf (Accessed: June 2015)

As a result of this trend in storage relative to demand, there may be tendencies for more market price volatility, particularly in winter months when loads are highest and when the pipeline and storage infrastructure are used at maximum capacity during very cold winters. Storage will remain an important tool for mitigating seasonal price risk exposure for customers, but additional hedging helps augment the benefit that storage brings.

Physical Fixed Price

A physical fixed price contract is an agreement with a counterparty to deliver a specified amount of physical gas at a specified point in time to a pre-defined location at a fixed price. Physical fixed price contracts are commonly used by utility companies to hedge against rising prices. The typical term of delivery for physical price contracts can vary, ranging from one month to ten years.

Physical fixed price contracts are effective in mitigating price exposure and meeting base-load supply needs. From the customers' point of view, these contracts can be very effective at providing reliability and rate stability. Generally, transaction costs are low and there are a number of willing sellers, particularly for short-term delivery periods. Market liquidity can vary greatly by location but generally the most liquid time horizon is one month to one year. Some transactions, however, are executed in the one to ten year time horizon. Typically, a highly-rated utility receives more open credit from counterparties with physical fixed price transactions than with financial transactions.

The risks associated with using physical fixed price contracts are force majeure events, counterparty credit default, and liquidity constraints. Force majeure events that prevent the supplier from delivering gas occur relatively infrequently, and gas storage often acts as a back-up supply. Physical gas suppliers as a group tend to have lower credit ratings than banks and large trading firms. Diversifying transactions with several high quality credit grade counterparties can mitigate some of the counterparty credit default risk. Credit threshold amounts and collateral posting requirements can be negotiated in physical fixed price contracts or associated enabling agreements. Transacting in a liquid market with multiple buyers and sellers can mitigate liquidity risk.

Figure 16 below illustrates how a fixed price transaction assures the purchase price to the utility regardless of what happens to market prices:

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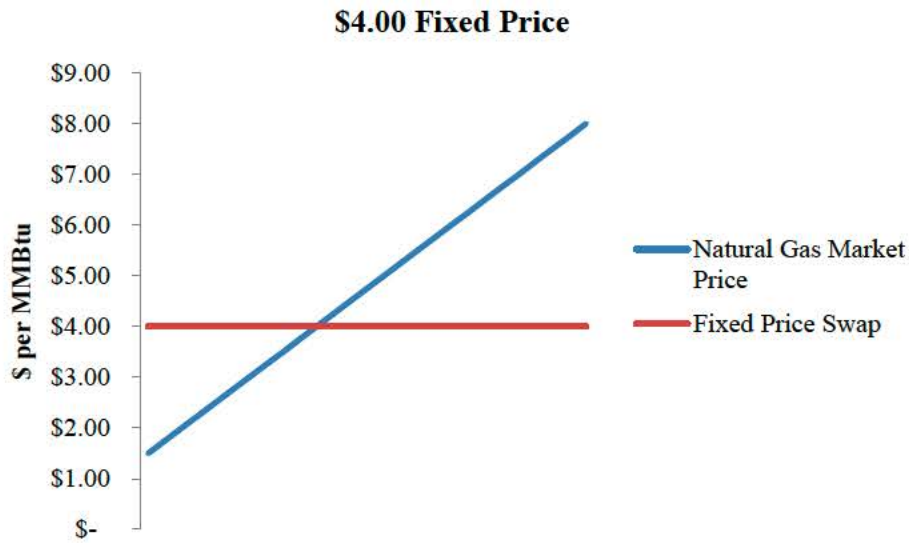
Figure 16 – Fixed Price Pay-Out



The benefit of a fixed price contract is that the cost is locked in. When a utility wants to lock in a specific cost, the low transaction cost and price certainty are important benefits to a fixed price contract. If a utility believes it is more likely that prices are going to rise than fall, coupled with a specific price target or a low risk tolerance, then the execution of a fixed price transaction to hedge price risk may be advisable. The downside, however, is that there is no opportunity to benefit if market prices fall below the price at which the fixed price contract is locked in.

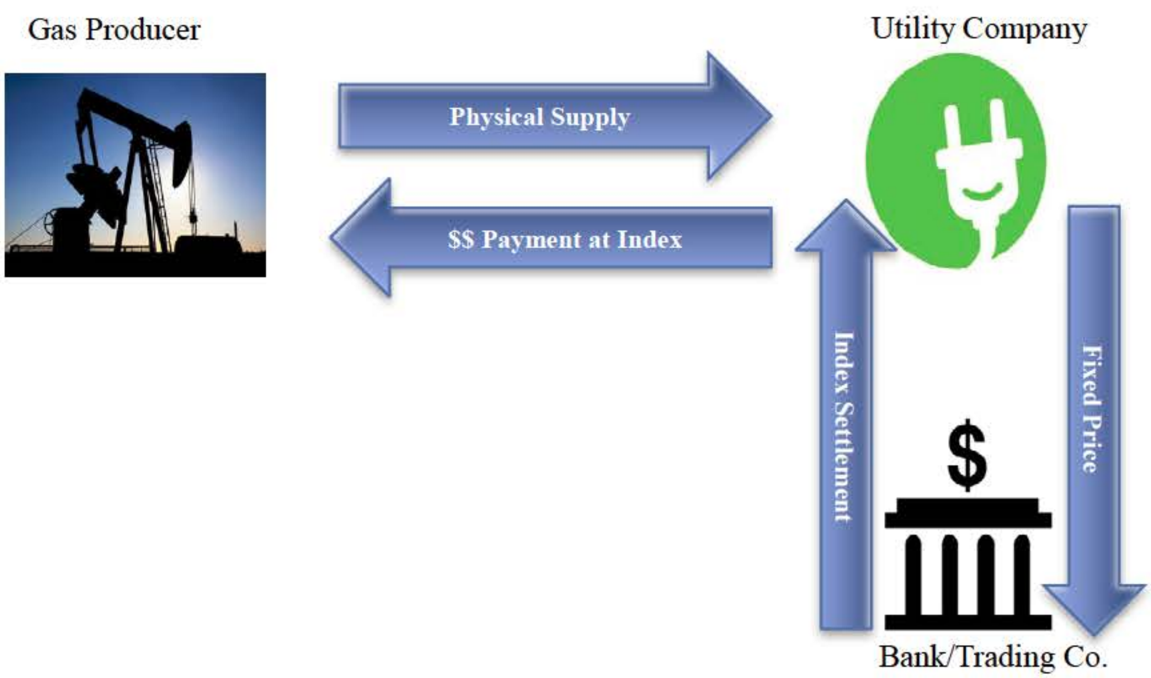
Financial Instruments

A. Fixed for Floating Swap ("Fixed Price Swap")

As an alternative to fixed price physical contracts discussed above, a common method to hedge fixed price risk is to use a financial swap called a "fixed for floating swap" or "fixed price swap". This is because physical suppliers often prefer selling at an index relationship and a different set of counterparties are willing to be market-makers in the financial swap market. A utility can buy physical gas at a posted index price from a marketer or producer and execute a financial fixed for floating swap that fixes the price of this index for the length of the contract. In some regional markets the fixed for floating swap can be transacted easily. When there is not much liquidity in the fixed for floating swaps at these locations, however, the utility may have to hedge at an alternative market location.

A fixed for floating price contract mitigates price exposure through a financial settlement. After the benchmark index price has been posted, the parties compare it to the original contract price. If the index price is higher than the contract price, the seller makes a financial payment to the buyer. If the index price is lower than the contract price, the buyer makes a financial payment to the seller. Figure 17 below illustrates the structure of a fixed for floating swap transaction:

Figure 17 – Physical and Financial Commitments Using a Fixed For Floating Swap



Often there is more liquidity (i.e. - more market participants and greater trading volumes) in financial swaps traded at major market hubs. As a result, they can have lower transaction costs than physical fixed price contracts. Notably, however, the financial swaps do not provide physical supply and the utility has to still acquire physical supply from a supplier. Liquidity can vary greatly by location but generally price visibility is available from one month to ten years at major trading hubs.

The risks associated with using fixed for floating swap contracts are counterparty credit default and new CFTC regulatory compliance. The swap contract provides slightly better price protection than the fixed price physical transaction since force majeure events affecting delivery of supply do not create issues. Diversifying transactions with several high quality credit grade counterparties can mitigate counterparty credit default risk. Transacting within a liquid market with multiple buyers and sellers can mitigate counterparty concentration risk. Compliance oversight and good risk management practices can also protect a utility from CFTC non-compliance risk.

Credit terms differ depending upon whether the utility is transacting bilateral contracts directly with counterparties or clearing swaps through a clearing firm. Credit threshold amounts and collateral posting requirements can be negotiated in a bilateral swap agreement. Entities with strong credit ratings have historically been offered a certain level of open credit (known as a "credit threshold") before margining is required by the counterparty for negative mark to market.

Typically, a utility has a great deal less open credit if it chooses to clear transactions with a clearing firm. Per the CFTC rules for cleared transactions, the utility would have to post initial margin along with variation margin associated with mark to market movements affecting the value of its contracts. The positive side is that there is minimal counterparty risk with cleared swap transactions since the CFTC has strict rules for maintenance of customer funds by clearing firms.

In response to the more significant reporting, capital, risk management, and end-user service requirements for swap dealers and major swap participants associated with new CFTC swaps regulation, Intercontinental Exchange (ICE) recently launched futures contracts that have similar characteristics to swaps that have traded numerous years at geographic locations. Therefore, an alternative to a cleared fixed for floating swap is to use futures for hedging. To mimic a cleared fixed for floating swap, the utility would purchase Henry Hub futures and basis futures at a location relevant to its portfolio.

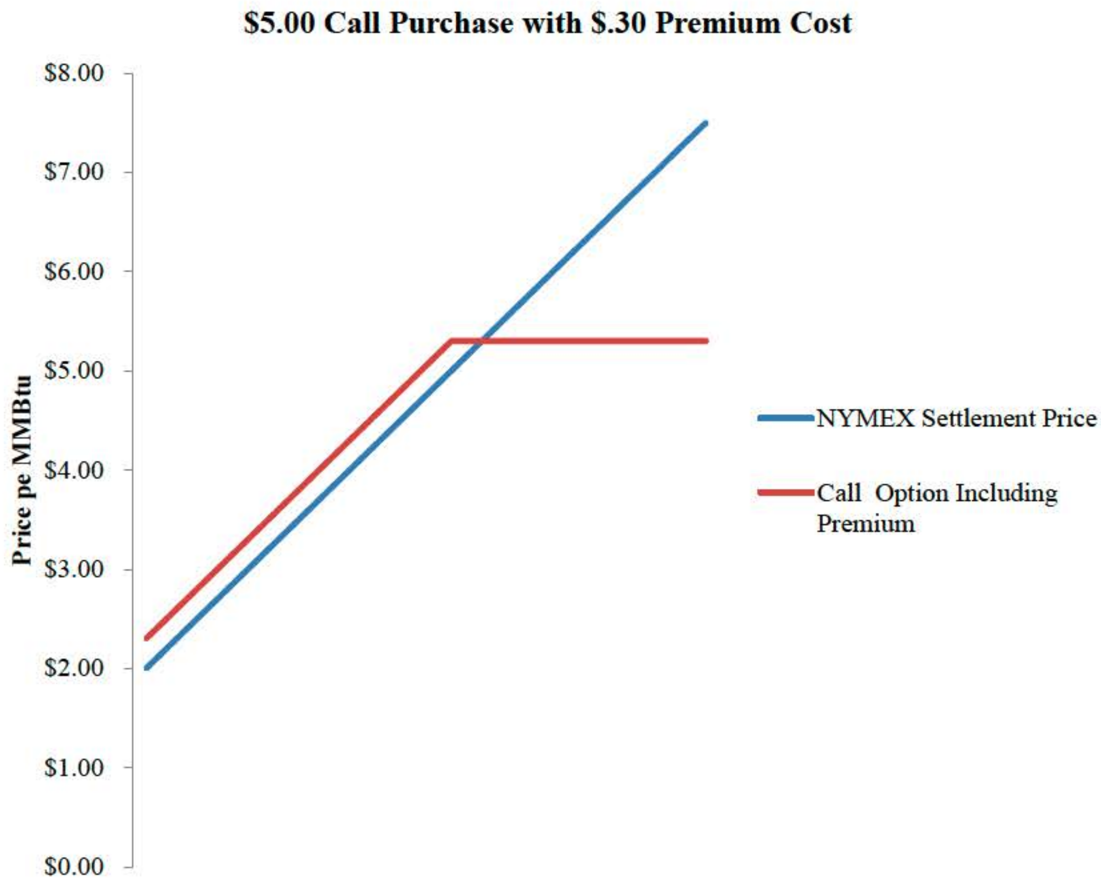
The advantage to a fixed for floating swap is similar to that of a physical fixed price, in that the cost is locked in. If a utility believes it more likely that prices are going to rise than fall, and it has a specific price target or a low risk tolerance, then the execution of a fixed for floating swap to manage price exposure may be advisable. But the downside is that there is no opportunity to participate in lower prices if the market price falls below the price at which the fixed for floating swap is executed.

B. Call Option

A call option is another way to hedge against increases in natural gas prices. Call options are most often structured as a financial instrument but may also come in the form of a physical contract. As a financial instrument a call option can be transacted as an exchange-based option or as an over-the-counter financial instrument.

A call option gives the buyer the right, but not the obligation, to buy gas at a fixed price at a specified point in time, location, and price (known as the "strike" price). The benefit of a utility using a call option as a hedging tool is that customers benefit if the market price falls. Figure 18 illustrates how an illustrative \$5.00 per MMBtu call option would protect the utility above \$5.00 /MMBtu:

Figure 18 – Call Option Pay-Out



However, this benefit comes at a cost, which is the premium paid for the call option. At the time of purchase, the utility pays a premium to the counterparty selling the call option. The amount paid is determined by several factors: 1) the strike price relative to the current forward price; 2) the amount of time to expiration of the call option; 3) expected market volatility; and 4) interest rates. The cost of an option increases the greater the time to expiration of the option and the greater the market volatility. Two other drivers to option cost are the proximity of the option strike price relative to the forward market price and the level of interest rates.

Some utilities purchase "out-of-the-money" call options to protect against significant upward movements in prices. This is potentially attractive when the purchaser has a relatively high risk tolerance. A utility might use out-of-the-money call options as a hedge strategy when it wants to protect against sharp increases in price, but also wants to retain the benefit if market price falls. Call options are attractive instruments to use in either falling markets or low volatility markets.

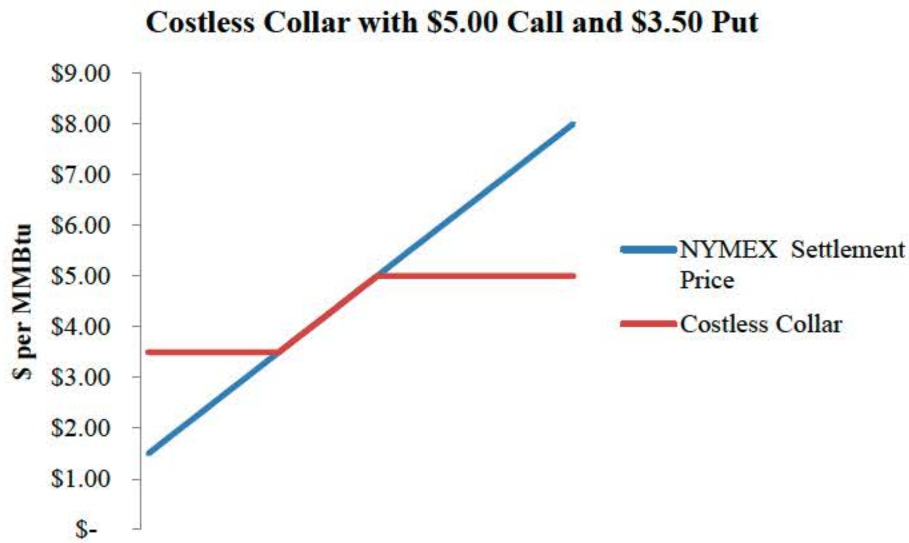
Similar to a fixed price physical contract or a bilateral fixed for floating financial swap contract, there is some counterparty credit default risk if the call is either a physical option or a bilateral financial option. The buyer pays a premium to the seller at the time the call is purchased. In exchange, the buyer is protected if the market price rises above the call strike price (either through physical delivery or financial payment based upon the strike price). If a call is transacted as a cleared financial instrument, then the utility has the credit protection of the clearinghouse and clearing firm. The initial and variation margin requirements would be much less with a call than a fixed for floating swap as the mark to market would only apply to the value of the premium. It is advisable to transact call options with liquidly-traded strike prices.

C. Collar

A collar (also called a "fence") combines a purchase of a call and the sale of a put (to finance the purchase of the call). The net effect is to create a range between high and low market prices where the utility purchases at the index, but is protected against rising prices by the ceiling (the strike price of the call option) and agrees to buy at the floor price (the strike price of the put option) in the event that prices fall.

The strike prices for the call and the put can be set to where there is no net premium cost for the buyer to develop a "costless collar". If market price increases, the utility is protected at the strike price of the call. If market price falls, the utility participates in the declining prices until the market price hits the put strike price (also called the floor price). The collar puts a range on the price so that the utility is purchasing somewhere between the call strike price and the put strike price. It can be structured as either a financial instrument or a physical contract, but most often as a financial instrument. Utilities sometimes use collars as an alternative to fixed price contracts to hedge six to twenty-four months forward in time. Because the utility is financing the purchase of the call by selling the put, the net premium cost is reduced. The instrument can be structured as a no-cost collar. Figure 19 illustrates a costless collar with a $5.00 per MMBtu call option and a $3.50 put option:

Figure 19 – Costless Collar Pay-Out



The costless collar is a sale of a put option in exchange for the purchase of a call option. The put option gives the buyer the right to sell gas to the utility. The call option gives the utility the right to purchase gas. When combined the effect is to put an upper and lower band on the cost of gas supply the utility will purchase. With a costless collar, the utility participates if prices fall from current forward market levels, down to the level of the put strike price. In the event the market goes up, the utility has protection over the strike price of the call option.

This can be attractive if markets are expected to be range-bound but the utility does not want to take the risk of not hedging. It is also a hedging instrument that can be used for hedging farther forward in time than a call option. While the call option premium increases with a longer time horizon, making it increasingly expensive to acquire, the costless collar has no premium payment. This is because the cost of the put option the utility is selling off-sets the cost of the call option that the utility is buying. However, the tradeoff is that if prices rise, the utility would have been better off purchasing a fixed price contract, since the protection in the collar does not start until prices rise above the call strike price. Conversely, if prices fall below the put strike price the utility would have been better off purchasing a call option.

The setting of the strikes for the call in a collar should be consistent with the utility's hedging objective and perspective on market prices. For example, if the utility feels comfortable with prices moving no more than 5% from current levels and the forward market is currently at $5.00/MMBtu, then the call strike would be set at $5.50/MMBtu. Generally, the floor is then determined by finding a put strike whose premium is the same cost as the premium for the $5.25 call. As a rule of thumb, the call strike price quotes are generally twice the distance from the at-the-money price than the put strike. For example, forward market is currently at $5.00/MMBtu, and the call strike is at $5.50 /MMBtu, the put strike might be around $4.75 /MMBtu.

Although there is no upfront cost associated with a collar, typically the distance from the "at-the-money" forward price and the call strike is greater than the "at-the-money" forward price and the put strike. Thus, the relative value to the utility of the call purchased may be less than the value of the put sold due to transaction costs and volatility skew. Often, utilities transact collars with a single counterparty, which reduces liquidity should the utility want to re-structure the instrument or change it to a different type of hedge. One way to mitigate that is to transact the call and put separately in order to simulate a collar. It is advisable to transact at the most liquid market locations, using call and put strike prices with the largest trading volumes. This may result in a small premium net paid or received to structure the call with more liquid strike prices.

As with a financial fixed for floating swap or a financial call option, the utility has the option to transact the collar as a bilateral transaction or a cleared transaction. If the market price falls below the put strike, the margin call will be similar to a fixed for floating swap. If the no cost collar is transacted bilaterally, the counterparty's credit requirements on the utility will be similar to those for a fixed for floating swap.

BHUH used no cost collars following the financial crisis in 2008. The decline in market prices was so steep that the floor price in a collar would have performed very similarly to a fixed price swap instrument. BHUH's use of call options provided both insurance and some price benefit for customers. This was an appropriate approach given the market conditions at the time.

Gas Production Investment

A. Volumetric Production Payment

In a Volumetric Production Payment (VPP), a buyer makes a lump sum pre-payment to receive future delivery of natural gas for a defined delivery period. The VPP volume is conveyed through the sale of a limited volumetric over-riding royalty interest (i.e., a non-operating interest). A VPP is similar to a pre-paid contract as the buyer makes a payment to the seller at the beginning of the delivery period for the net present value of the volume to be delivered over time. Once the producer has delivered the volume, the conveyed interest reverts back from the buyer to the seller. A producer will often use the VPP payment to finance new exploration and production.

The VPP is a firm delivery contract, usually subject only to force majeure events in the field or in route to the delivery point (and for which production is made up at a later date). The gas may be delivered to the buyer in the field or at a mutually agreed upon delivery point. The delivery volume can be fixed over the term of the agreement. Usually the seller, not the buyer, incurs production cost risks.

These transactions are most attractive when the buyer's cost of debt is much lower than the producer's. The differential between the buyer's cost of capital and the seller's cost of capital may result in net present value cost that is more attractive on a levelized basis than a forward fixed price contract. The higher the credit rating of the buyer relative to that of the producer, the larger this benefit will be.

There have not many of these transactions executed. Since 2006, investment banks have most often served as counterparties in VPPs with producers trying to access capital. As an example, Chesapeake Energy (Chesapeake) transacted 5-20 year VPP transactions aggregating to $6.4 billion with Wells Fargo, Barclays, and Morgan Stanley from 2007 to 2012. The structures were backed with low-risk proved, developed producing reserves, similar to collateralized loans. At the time of the Barclay VPP in 2012, S&P rated the VPP notes at BBB, several notches above Chesapeake's corporate credit rating of BB+, illustrating the lower risk associated with the VPP. Other producers who have executed VPPs include Pioneer Natural Resources, Dominion Resources Inc., KCS Energy, and Obsidian Natural Gas.

There are some limitations associated with VPPs. Because a VPP is a non-operating interest, the buyer does not typically participate in the life of the reserves or share in new drilling costs and associated production opportunities. The transaction is typically structured where the amortization schedule of the VPP volumes matches or exceeds the expected production decline to insure there is an adequate cushion through the term of the transaction. With a VPP, a buyer assumes reserves risk, but this is mitigated in that the buyer usually has contractual rights to production in the producer's proved producing properties. However, since the production arrangement looks much like a forward contract and less like an ownership interest, in a bankruptcy preceding the volumetric production payment arrangement would likely not receive the same protection as direct ownership in reserves. Legal advice should be sought on structuring a volumetric production payment contract to understand all the legal considerations. Finally, the IRS has determined that a VPP must be recognized as a debt obligation by the seller, and the rating agencies have adopted this in their ratings criteria.[9]

[9] Standard & Poor's Criteria | Corporates | Industrials: *Volumetric Production Payments (VPPs) For U.S. Oil And Gas Exploration And Production Companies*, January 2009.

B. Reserves Investment

A direct investment in gas reserves puts the buyer in the role of a gas producer. There are several ways to structure a reserves investment. One approach is for a buyer to acquire proved producing properties where the production has already been found and the decline curve is predictable. The buyer acquires a working interest with a share in production over the life of existing wells. Another approach is for a buyer to participate not only in current production but also in drilling with the producer. There may be greater risk in drilling but lower cost and more upside opportunity. This latter approach is called a "Carry and Earn" or "Drill to Earn" working interest, where the buyer contributes capital to new drilling. In this fashion the non-operating interest owner participates along-side the producer and other owners to retain the same future % ownership in the properties. The buyer and the producer's positions are aligned in terms of the decline curve and new production additions, as opposed to a VPP that gives the buyer a preferential position with respect to production.

There is more volumetric variability in owning reserves. Field production can vary on a daily or monthly basis, in contrast to a VPP. Also the value of reserves will move up and down with the forward price of gas. Reservoir engineers estimate the volume of reserves every 1-2 years. Reservoir estimates of proved undeveloped properties are based upon the forward market price as a determinant of economically feasible production. If market prices rise from current levels, the value of the reserves investment increases not only from the higher value for current producing properties, but also for non-producing reserves that would be now economically viable to produce at the higher market prices.

There are operating considerations associated with an operating interest in reserves as opposed to a VPP. A reserves owner is subject to future environmental regulation for the life of the wells. There can also be operational risks associated with reserves, such as water seepage in gas wells or possible failure of new drilling to yield high-producing wells. However, operating risks are mitigated since the buyer has aligned interests with the producer that holds a majority interest

The due diligence required for a reserves investment is significant. The buyer reviews reserve reports, title searches, field operations data, permits, royalty agreements, environmental regulation, and tax obligations. Since the reserves buyer is responsible for paying taxes, royalties, and other related production costs, there are more administrative responsibilities with reserves ownership than with a VPP. But this can be mitigated by outsourcing the administrative work to the operator or another interest owner.

In terms of investment criteria, the operating history, experience, reputation, and financial stability of the producer is critical. Additionally, the cost of production is important to understand; the lower the cost of the properties and the cost to produce gas, the less risk there is of future de-valuation of reserves. Well spacing allowed on the land is also a consideration for valuation purposes. It is also important for the buyer to understand the production costs such as variable operating costs, value of the excess liquids, processing costs, and gathering costs.

The buyer will have to compare and contrast the benefits and considerations of receiving proceeds from the marketing of the production gas or to taking the production in kind. While it is a more direct link to the utility's gas supply to take the production directly to the utility's system, there also may be tax benefits to taking the gas proceeds in lieu of the physical gas, which should be explored with tax counsel.

Comparing VPPs and Long-Term Fixed Price Contract to Gas Production Investment

There are a number of considerations when comparing long-term fixed price contracts to owning production. These include volume delivered over the period, market liquidity, credit considerations, and operating matters.

There are a number of benefits associated with acquiring reserves as opposed to a VPP. For the buyer, the combined cost of the purchase of reserves and the estimated future production costs can be a significant discount on an NPV basis to a forward contract(this differential represents the producer's embedded margin). The buyer holds title to a physical asset as opposed to a limited volumetric over-riding royalty interest. Reserves are an asset that can be pledged as collateral or sold if such an action was required.

The location of the field and the composition of dry gas and natural gas liquids determine the value of the marketing proceeds. In terms of the value of the dry gas, the utility should understand the price differentials and market relationships between where the gas is produced and where the utility buys gas supply for its customers. There is less locational basis risk if the buyer invests in properties that have similar market price dynamics as the regulated customers' gas supply requirements. If the production were located in a different geographical location, the utility could manage locational risk using basis swaps or basis futures. However there would be limited opportunities to hedge the locational price risk outside of the medium-term time horizon of one to three years.

A. Volume Delivered Over the Period

The volume of gas delivered differs between a fixed price contract or VPP and owning reserves. With a fixed price contract or VPP, the buyer and seller agree on the volume to be delivered over the delivery period, whether it is a constant volume or a different volume by month or year. The volume to be delivered is defined in the agreement. But the delivery term with gas production investment is usually longer than what can be contracted through a fixed price contract.

Natural gas wells have decline curves, where the production peaks at the beginning of a well's life and declines over time until the well is depleted. To maintain production volumes at a steady rate, producers drill new wells. New well production replaces the declining production coming from existing wells. If a utility acquires only producing properties, it is has less volume in later years than in the early years as the fields are depleted. But, the gas well decline curve can work well in a utility hedging program if the utility can direct the pace of future drilling. The utility can adjust the drilling plan per forward market price signals. For example, if the market prices rise higher than the utility had originally forecasted, the utility can increase the pace of the drilling program to add production sooner than originally planned. And if market prices decline, the utility can slow or stop new drilling activity, in order to rely more on short-term hedging and spot market purchases.

The graph below from the Energy Information Administration's Annual Energy Outlook 2012 illustrates production curves for a variety of different shale gas regions. The larger graphic represents the daily well-head production, illustrating how production peaks early in the well's extraction. The smaller graphic in the upper right corner of the figure illustrates the cumulative production, also referred to as the estimated ultimate recovery (EUR), which is the amount of total estimated production that will be recovered over the life of the well.

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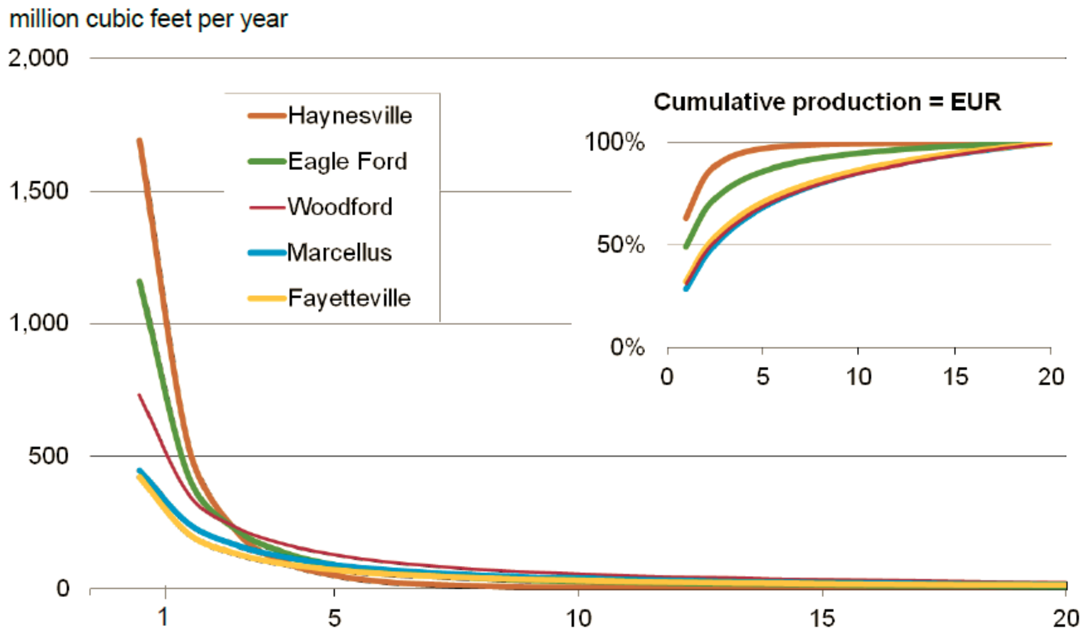
Figure 20 – EIA's Illustrative Decline Curve and Estimated Ultimate Recovery



Source: EIA, Annual Energy Outlook 2012

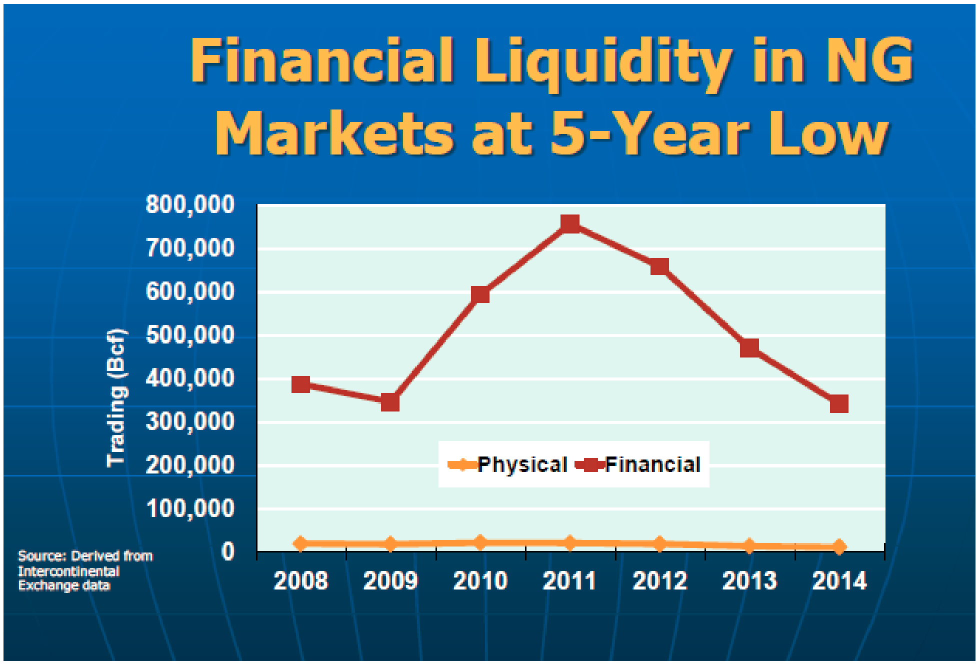
The value of an existing producing property is calculated using forward market prices, the EUR, the rate at which gas will be extracted, and the fixed and variable costs of production. If there are future drilling opportunities, the additional value is calculated by the amount of proved non-producing reserves, the estimated EUR, and the drilling and extraction costs to drill and bring the gas to market.

To summarize, if a utility wanted a steady production curve, there are two strategies that could be pursued. The first would be to buy mature existing producing properties, after the initial steep decline in the production curve has passed. The second would be to more actively manage gas production through deploying capital to new drilling, in response to forward market price signals. With either approach a utility would want to complement the long-term gas production hedge with a short-term and medium-term hedging plan. In Part V – Conclusions and Recommendations, Aether recommended an approach to integrate short-term, medium-term and long-term hedging.

B. Market Liquidity and Pricing

Market liquidity and pricing can be a constraint when trying to purchase long-term gas supply. It may be challenging for the utility to find many market participants willing to offer physical fixed price transactions or fixed price swaps outside of the three to five year time horizon at attractive prices. Reduced natural gas market liquidity was reported by FERC staff to the FERC commissioners in a March 2015 report:

Figure 21 – Natural Gas Market Liquidity[10]



According to the FERC staff presentation notes, the red line in the graph above represents the sum of all domestic natural gas financial products traded on ICE, including futures, swaps and spreads at all hubs:

> *The majority of the volume, approximately 90% in 2014, consists of trading in the Nymex Look-Alike futures contract. The yellow line represents the sum of all physical volumes traded on ICE at all hubs including spot and monthly transactions. The financial to physical ratio is approximately 30 to 1. Natural gas trading volumes declined in 2013, for the fourth straight year. Financial volumes on ICE declined over 25%, in step with the drop on the Chicago Mercantile exchange. Financial volumes continue to significantly outweigh physical volumes and were 30 times larger in 2014. The sustained increase of natural gas production across the U.S. led to lower and more stable natural gas prices over the past several years. Less volatile prices hurt speculative trading profits, this caused companies, particularly large banks, to reduce or eliminate their*

[10] Federal Energy Regulatory Commission, *2014 State of the Markets, Item No. A-3, March 19, 2014*, FERC Staff presentation to FERC Commissioners.

trading exposure. As a result, physical and financial trading has fallen significantly from its highs in 2011.”[11]

This issue of liquidity is illustrated by looking at the open interest of the CME Henry Hub futures contract. The Henry Hub futures market serve as the proxy market for most North American natural gas markets. Very significant volumes of futures contracts are traded in this market, but the trading volume is concentrated in the next one to five years. The lack of volume executed beyond five years into the future at the CME Henry Hub natural gas futures market is an indicator of illiquidity in other forward markets.

To illustrate this, Aether examined the net open interest of all CME Henry Hub Natural Gas futures months. Open interest represents the current net open long and short positions of all entities holding futures contracts in those months as of the close of trading June 12, 2015. At any given point of time, open interest increases and decreases, depending upon the appetite for trading and hedging among all the market participants. The data represents open interest at a single point in time, and at other times open interest may be greater or smaller. But there is a strong tendency for the net open interest to be concentrated in the first few years of the futures contracts’ trading months. The low open interest beyond the first five years, from 2019 to 2024, is indicative of lower market liquidity in long-term markets.

Figure 22 – CME Henry Hub Futures Net Open Interest (June 22, 2015)

Year	Open Interest Contracts	Equivalent Volume MMBtu/day
Balance 2015	736,769	40,041,793
2016	251,758	6,897,479
2017	31,281	857,014
2018	5,963	163,370
2019	4,684	128,329
2020	538	14,740
2021	362	9,918
2022	4	110
2023	6	164
2024	9	247

[11] Federal Energy Regulatory Commission, , The Office of Enforcement’s Division of Energy Market Oversight, *2014 State of the Markets, Item No. A-3*, March 19, 2015, https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2014-som.pdf (Accessed: June 2015)

Year	Open Interest Contracts	Equivalent Volume MMBtu/day
2025	0	-
2026	0	-
2027	0	-

In contrast, a reserve transaction is for a long-term time horizon given the wells' twenty year or longer production curve.

C. Credit Considerations: Counterparty Risk and Collateral Posting

Two other considerations are counterparty credit risk in the event the seller fails to perform and the burden of collateral posting requirements for the utility. With a conventional long-term fixed price purchase or a financial swap purchase, there is risk of future non-performance. If the utility purchases a financial swap or fixed price physical contract, and the counterparty defaults after market prices have risen above the price of the contract, the utility has liquidated damages replacing the supply at the higher market prices. BHUH can mitigate the risk of default in part by transacting with credit-worthy counterparties, but this reduces the pool of potential suppliers. Below is an illustrative list of high investment grade entities active in the markets in which BHUH hedges:

Figure 23 – Illustrative Rated Counterparties[12]

	S&P Rating[13]
Anadarko Petroleum	BBB
BP America Production Co.	A
Cargill Inc.	A
Centerpoint Energy Inc.	A-
ConocoPhillips Co.	A
Chevron Corp.	AA
Constellation Energy/Exelon	BBB
Goldman Sachs[14]	A-

[12] This is not an exhaustive list of entities transacting in natural gas financial and physical markets but an illustrative list. Aether is not endorsing any of these entities but has included sample market participants to show an illustrative range in credit ratings of large market participants.
[13] Standard & Poor's, Local Currency Long-term ratings, http://www.standardandpoors.com/en_US/web/guest/home (Accessed: June 2015).

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Macquarie Energy/Macquarie Group	BBB
Marathon Oil Corp.	BBB
Oneok Inc.	BB+

There is a credit cost savings to owning reserves as opposed to contracting for long-term supply. To compare and contrast the implied credit cost of a fixed price contract to an investment in reserves, one could apply an average default rate associated with a rating modifier to an entity with that credit rating, to develop an assessment of the risk premium of contracting for supply as opposed to owning supply. Below are Standard & Poor's global corporate annual default rates by rating category by year from 1981 to 2014. The highlighted columns AA, A, and BBB correspond to the range of credit ratings of BHUH's counterparties.

Figure 24 – S&P 2014 Report [15]

Global Corporate Annual Default Rates By Rating Category (%)

Year	AAA	AA	A	BBB	BB	B	CCC/C
1981	0	0	0	0	0	2 27	0
1982	0	0	0 21	0 34	4 22	3 13	21 43
1983	0	0	0	0 32	1 16	4 58	6 67
1984	0	0	0	0 66	1 14	3 41	25 00
1985	0	0	0	0	1 48	6 47	15 38
1986	0	0	0 18	0 33	1 31	8 36	23 08
1987	0	0	0	0	0 38	3 08	12 28
1988	0	0	0	0	1 05	3 63	20 37
1989	0	0	0 18	0 60	0 72	3 38	33 33
1990	0	0	0	0 58	3 57	8 56	31 25
1991	0	0	0	0 55	1 69	13 84	33 87
1992	0	0	0	0	0	6 99	30 19
1993	0	0	0	0	0 70	2 62	13 33
1994	0	0	0 14	0	0 28	3 08	16 67
1995	0	0	0	0 17	0 99	4 58	28 00
1996	0	0	0	0	0 45	2 91	8 00
1997	0	0	0	0 25	0 19	3 51	12 00
1998	0	0	0	0 41	0 82	4 63	42 86
1999	0	0 17	0 18	0 2	0 95	7 29	33 33
2000	0	0	0 27	0 37	1 15	7 67	35 96
2001	0	0	0 27	0 34	2 94	11 52	45 45
2002	0	0	0	1 02	2 88	8 20	44 44
2003	0	0	0	0 23	0 58	4 06	32 73
2004	0	0	0 08	0	0 43	1 45	16 18
2005	0	0	0	0 70	0 31	1 74	9 09
2006	0	0	0	0	0 30	0 82	13 33
2007	0	0	0	0	0 20	0 25	15 24
2008	0	**0.38**	**0.39**	**0.49**	0 81	4 08	27 00
2009	0	0	0 22	0 55	0 75	10 92	49 56
2010	0	0	0	0	0 58	0 85	22 73
2011	0	0	0	0 07	0	1 66	16 42
2012	0	0	0	0	0 3	1 56	27 33
2013	0	0	0	0	0 09	1 63	24 18
2014	0	0	0	0	0	0 77	17 03
Average	0	**0.02**	**0.06**	**0.24**	0 95	4 51	23 64
Minimum	0	0	0	0	0	0 25	0
Maximum	0	0 38	0 39	1 02	4 22	13 84	49 56

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[14] Black Hills' rating for this counterparty.
[15] Standard & Poor's Ratings Services, *2014 Annual Global Corporate Default Study and Ratings Transitions*, April 30, 2015.

To compare the risk associated with owning gas production versus forward contracting supply, a utility could apply the credit default risk rating to the cost of the supply. In Example 1 below, Aether shows the effect of applying the average default rate from 1981 to 2014 for AA, A and BBB rated entities (.02%, .06% and .24%) to determine the benefit of purchasing gas as opposed to owning gas production. At a $4.50 /MMBtu contract price, the implied credit cost for rated entities using historical average default rates by rating category is: $.0009 /MMBtu for AA rated entities, $.0027 /MMBtu for A rated entities, and $.0108 /MMBtu for BBB rated entities:

Example 1: Apply weighted average corporate defaults rates by rating category

10-year Northern Natural Demarcation fixed price swap for 5.000 MMBtu per day beginning November 2015, at a fixed price of $4.50 MMBtu with a) an AA-rated entity, b) an A-rated entity and c) a BBB-rated entity.

a) AA-rated entity

$4.50 * weighted default risk of .02% = Implied credit risk
$4.50 * .0002 = $.0009/ MMBtu

b) A rated entity

$4.50 * weighted default risk of .06% = Implied credit risk
$4.50 * .0006 = $.0027/ MMBtu

c) BBB rated entity

$4.50 * weighted default risk of .24% = Implied credit risk
$4.50 * .0024 = $.0108/ MMBtu

These calculations do not result in material credit costs. However, using an average historical default rate understates the risks during times of economic and financial stress. During the financial crisis in 2008, several large banks and an insurance company failed financially, notably Bear Stearns, Lehman Brothers, and AIG. And in 2011, a large futures commission merchant, MF Global, filed for bankruptcy. All these entities were active in energy markets either directly or through subsidiaries.

Given that natural gas production is a long-lived asset, it would be more appropriate to look at historical credit defaults during times of financial stress. Using the example above, the utility could apply a default rate for a period of financial stress, such as 2008, to ascertain potential risk during turbulent financial markets. At a $4.50 /MMBtu contract price, the implied credit cost for rated entities using 2008 average default rates by rating category is: $.0171 /MMBtu for AA rated entities, $.0176/ MMBtu for A rated entities, and $.0221 /MMBtu for BBB rated entities:

Example 2:

b) AA rated entity

$4.50 * weighted default risk of .38% = Implied credit risk
$4.50 * .0038 = $.0171/ MMBtu

b) A rated entity

$4.50 * weighted default risk of .39% = Implied credit risk
$4.50 * .0039 = $.0176/ MMBtu

c) BBB rated entity

$4.50 * weighted default risk of .49% = Implied credit risk
$4.50 * .0049 = $.0221/ MMBtu

This results in higher implied credit costs of long-term contracts than a historical average default rate approach. Further, an industry sector assessment can be valuable. Standard & Poor's aggregated data by industry sector in its 2014 global corporate default rates by industry is provided below in Figure 25.

Figure 25 – Corporate Default Rate by Industry[16]

Global Corporate Default Rates By Industry (%)

	2014	2013	Weighted average (1981-2014)	Median	Standard deviation	Minimum	Maximum
Aerospace/automotive/capital goods/metal	0.5	0.6	2.3	1.3	2.1	0.0	9.6
Consumer/service sector	1.1	0.9	2.3	1.6	1.7	0.0	6.3
Energy and natural resources	2.1	1.9	1.8	1.4	2.1	0.0	10.1
Financial institutions	0.2	0.3	0.7	0.3	0.7	0.0	2.7
Forest and building products/homebuilders	0.0	4.2	2.6	1.4	3.0	0.0	14.3
Health care/chemicals	0.7	1.3	1.5	0.8	1.4	0.0	4.8
High technology/computers/office equipment	1.5	0.0	1.2	1.0	1.5	0.0	4.9
Insurance	0.0	0.0	0.4	0.3	1.0	0.0	5.1
Leisure time/media	2.3	4.3	3.7	2.2	3.4	0.0	17.0
Real estate	0.0	1.0	0.8	0.0	2.5	0.0	9.7
Telecommunications	0.5	2.9	2.9	0.7	4.1	0.0	18.9
Transportation	0.8	2.3	2.1	1.9	1.7	0.0	6.1
Utility	0.3	0.2	0.5	0.2	0.8	0.0	4.2

Note: Includes investment-grade and speculative-grade entities. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditPro®.

Applying the weighted average (1981-2014) corporate default rate for "Energy and Natural Resources" of 1.8% and for "Financial Institutions" of 0.7% would yield the following implied credit risk cost to a fixed price contract:

Example 3: Applying Sector Corporate Default Rate

10-year Northern Natural Demarcation fixed price swap for 5.000 MMBtu per day beginning November 2015, at a fixed price of $4.50 MMBtu with a) an energy and natural resources company and b) a financial institution.

a) Energy and natural resources company

$4.50 * weighted default risk of 1.8% = Implied credit risk
$4.50 * .018 = $.081/ MMBtu

[16] Ibid.

b) Financial institution

$4.50 * weighted default risk of .7% = Implied credit risk
$4.50 * .007 = $.032/ MMBtu

Other scenarios could be applied, such as applying the highest default rate in any given year, as opposed to the weighted average.

Whichever default rating is used, it should be noted that default risk ratings represent the current financial worthiness of the entity and it is not a guarantee of future financial strength. So, while it is common practice to look at a probabilistic expected outcome, it is important to understand the event is binary, where default either occurs or it does not occur. In the cases of Bear Stearns, Lehman Brothers, AIG, and MF Global, their financial failure happened over a short time span that would have been difficult to foresee.

The discussion above addresses the counterparty credit risk considerations. But there are also collateral considerations for the utility. In a long-term fixed price supply contract, the seller would typically require credit provisions in the contract for collateral posting in the event the market price moved against the buyer (i.e., if market prices declined). Typically this is a bilateral arrangement, providing similar protection to the buyer, in the event the market prices moved against the seller (i.e., if market prices rose). Whether the long-term contract was a bilateral agreement, or a cleared transaction where the participants agreed to clear the transaction through a clearing party such as Intercontinental Exchange (ICE) or the CME, there would be collateral posting requirements.

The utility would be asked to post collateral if market prices declined below the contract price. This is because the seller would incur market damages if the utility did not perform (if it failed to take and pay for the gas at the contract price). The seller would have to find another market at a lower price and the collateral protects the seller from the risk of market damages. The table below in Figure 26 provides some examples, assuming a contract with a levelized $4.50 purchase price and a material downward market price move one year into the contract. The greater the volume and term of the transaction, the more significant the collateral posting could be. The table shows the effect of a five year, ten year and fifteen year contract term, for changes in market prices of 20%, 30%, and 40% ratably across the forward price curve.

Figure 26 – Potential Collateral Call ($4.50 /MMBtu Purchase Price)

Volume/ Day	Term of the Contract	% Move in the Forward Market	$/ MMBtu Change ($4.50 Price)	Resulting Collateral Call
10,000	5	20%	$0.90	$13,140,000
15,000	10	30%	$1.35	$66,521,250
20,000	15	40%	$1.80	$183,960,000

The collateral requirement can grow exponentially: the larger the contract quantity, the longer the open remaining time on the contract, and the larger the differential between market price and the contract price. In the table above, a utility could likely manage the credit call for the first example of $13 million with an existing credit facility (10,000 MMBtu/day, four years remaining in the delivery period, and a 20% market price move). Generally, the utility's credit facility is sized to accommodate unusual events, and the utility could draw down the facility to post the required collateral either directly to the seller or to the Futures Commission Merchant (FCM) if this were a cleared transaction such as a fixed price financial swap.

But the more extreme third example would pose serious challenges and costs. Credit facilities are negotiated on a case by case basis, but there could be a 1%-3% cost associated with posting this collateral depending upon the circumstances and the utility's credit rating. Moreover, this would increase the debt position of the utility by having to borrow to post the collateral. As a result, collateral posting terms can become problematic. The parties could agree to waive collateral posting requirements or put a cap on the amount that would be posted by either party, but then the utility would be more exposed to a risk of default by the seller.

D. Ownership of Gas Compared to Contractual Rights to Gas

Another valuation consideration when comparing a long-term fixed price contract to ownership of reserves is the value of having title to the gas production. When a utility owns reserves, it has legal title to gas production, as opposed to a contractual obligation for future delivery. Some utilities place great value on owning the asset and refer to how this meets reliability requirements, as opposed to a financial swap which would only provide financial protection. There is more 'security' of supply associated with gas production ownership than with a physical or financial purchase contract.

When a buyer acquires gas reserves it is typically an "in the ground" transaction, where the buyer bases its purchase price upon expected volume delivered over a future period at a certain decline rate, which is supported by reservoir engineering reports. There are typically different categories of reserves, such as proved producing, proved un-developed, and probable reserves. The buyer assigns different values or probabilities to each type when developing a valuation price, depending upon the confidence level, forward prices, and estimated cost of bringing each category of reserves to market. So a reserves acquisition is not just a fixed price investment for the proved producing gas, but also a series of options to bring to market proved un-developed and probable reserves.

E. Operating Considerations With Reserves

The primary operating considerations with gas reserves relate to the feasibility of extracting the estimated available reserves at the estimated extraction cost. This comes down to the confidence of the commercially available reserves and the costs to bring those to market. These risks can be mitigated by acquiring reserves in producing fields in well-explored basins, partnering with knowledgeable producer partners, and engaging reputable engineers and other advisors.

The lifting costs to extract the natural gas, process it, and deliver it into the interstate pipeline system are paid out over the life of the well, as the gas is produced. An acquisition can be structured where the operator (which is often the producer partner who is the majority owner in the field) extracts the gas and re-delivers it to the utility or markets it on behalf of the utility. It is important for the utility to understand the drivers to the lifting costs. The future production cost estimates should be reviewed carefully to understand how the unit cost may change as production declines in the field.

Further, the utility should choose a producer partner that has a strong operating history, experience in the drilling technology and extraction methods, and financial stability. Ideally, the producer will have an operating history in the field in which the utility will buy reserves. Hence a valuation consideration would be the strengths and experience of the field operator. The most attractive field operating partners will be those that have aligned incentives to the gas production owner(s), have credible operating experience, and can financially meet their performance obligations.

Another valuation consideration would an assessment of the value of any natural gas liquids associated with the wet gas. As for the natural gas liquids, the composition of the liquids should be understood in terms of both how much of the liquids could stay in the gas stream to comply with pipeline specifications when liquids prices are low as well as how much of the liquids can be extracted when liquids prices are high. Just as a forward price curve is used to evaluate the value of the dry gas production, similarly a forward price curve should be used to evaluate the value of the natural gas liquids (ex: ethane, propane, and normal butane). The buyer would want

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to understand how the value of the investment changes with higher and lower natural gas liquids prices.

With any arrangement in which there is a “carry to earn” or “drill to earn” mechanism, a buyer will want to understand the cost of exploratory drilling and the expected success rate, to ascertain the risk profile and the opportunities. The cost of a “drill to earn” structure is represented by the exploration cost, the cost to produce successful wells, and the carried interest the producer receives. These should be examined relative to the forward market price, as well as relative to what the buyer needs for its portfolio. Additionally, in a “drill to earn” structure, the buyer will want to understand the ramifications if it elects not to participate in the exploratory drilling (ex: dilution of interest in the project). If the drilling plan assumed a certain number of wells with a specific spacing, but that changed to where the drilling concentration was increased, then it is possible the reserves in the field would be depleted more quickly than originally estimated. To the degree a buyer had not participated in the new drilling, its share of the total production of the field might be diminished.

There are additionally operating considerations to weigh. After the first natural gas production acquisition, subsequent gas production acquisitions may offer economies of scale and be a strong strategic fit for the utility. For example, there would be added benefit if the new acquisitions could be incorporated into the current production portfolio without the utility having to incur significant third party operating costs or adding internal overhead to manage the gas production, thereby lowering costs on a per unit basis for customers. This last benefit has to be considered in light of potential risks though. For example, the utility may decide it wants to diversify its gas production holdings in more than one geographical region or with more than one gas producer.

F. Summary

The summary table below lists the benefits and considerations associated with the four long-term hedging alternatives: fixed price contract, volumetric production payment, proved reserves, and drill to earn. If a utility feels comfortable assuming the exploration and production risks, the drill to earn approach provides the greatest flexibility and cost advantage of the four alternatives.

Figure 27 – Comparison of Long-Term Hedging Alternatives

Long-term Hedging Strategy Options	Benefits	Considerations
Fixed Price Contract	• Volumes can be fixed or customized • Cost is known • Seller bears production risk	• Large counterparty credit risk if prices rise and collateral posting if prices fall • Lack of market liquidity • Limited time horizon
Volumetric Production Payment	• Volumes can be fixed or customized • Lower cost than fixed price purchases • Non-operating interest • Seller bears production risk • Backed by proved producing reserves • No collateral posting required and much reduced counterparty risk • Cost is known	• Prepayment treated as debt for producers • Limited number of transactions available • May not be bankruptcy proof
Proved Reserves (no drilling)	• Sales of reserves are commonplace • Lower cost than VPPs or fixed price purchases • Asset ownership • No collateral posting or counterparty risk • Cost of production in ground is predictable	• Buyer may assume future operating and environmental risks • Production decline curves do not match load requirements
Drill to Earn	• Lower cost than proved reserves, VPPs, and fixed price purchases • Sales of reserves are commonplace • Asset ownership • No collateral posting or counterparty risk • Cost of initial production in ground is predictable • Decline curve can be managed with drilling	• Buyer may assume future operating, drilling, and environmental risks

Utility ownership of reserves can be an effective way to cost-effectively manage gas supply costs and stabilize rates for customers. The risks can be mitigated by managing operational costs, working with a reputable producer partner, and engaging reserve engineers to monitor reserves. A drill to earn structure allows the utility to optimize production by managing future investments relative to forward market prices.

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Part 3 – Long-Term Factors and Opportunity Assessment

Summary

A long-term hedge is a significant resource for the utility to commit to on behalf of customers. Since a long-term fixed price supply contract or resource has long-term rate implications, it must provide sustainable, long-term benefits to customers. From the utility's perspective, long-term hedges take time to structure and require considerable due diligence. Long-term hedges also hold more risk than short-term transactions. If the long-term hedging transaction is a fixed price physical or financial contract, there are material credit and counterparty considerations. If it is a gas production arrangement, significant capital investment will be required. And there can be regulatory risk for the utility if the transaction goes awry or if regulators do not support long-term price risk management.

Prior to executing a long-term hedge, the utility must have support from stakeholders and regulators. Having common goals for a long-term gas supply investment helps the utility confidently proceed with due diligence and efficiently close transactions that bring value to customers through reliable, stable and attractively-priced long-term supply. Agreement among the parties on what defines a valuable resource or contract is important.

Part 3- Long-Term Factors and Opportunity Assessment provides factors supporting long-term hedging. A long-term hedging opportunity should be examined from a market price context and an assessment of supply and demand factors. Long-term hedging should be considered when supply can be acquired at attractive levels, particularly when there is uncertainty regarding potential declining supply and/or increasing demand.

Market prices are likely to increase from current levels given forecasted supply and demand trends. Production is stable and predicted to continue growing, but the market price is not high relative to production costs, so producer margins and profitability are modest. This could constrain supply in the future, unless prices rise to encourage more production. An additional factor on the demand side is that demand is predicted to increase at a significant rate to meet new electric generation demand, transportation fuel demand and LNG export demand. While the past eight to nine years have been a supply-driven market, indications are that this will change in the coming decade to a demand-driven market.

Price Context

There are several key considerations to determine the value of a market relative to other markets. The first is a historical context to understand how the forward price compares to previous market price observations. Related to that is price escalation over time. Natural gas markets are typically in contango, where forward year prices carry an annual price escalation. So, in addition to looking at the levelized price, another measure of relative value is what type of annual escalation from current year prices is built into the long-term price.

Additionally, the price of a long-term hedge should be evaluated in the context of customers' rates. This is especially relevant to consumer costs, as consumers have a bill history for context. For example, if a long-term hedge can be layered in at a price level that is attractive relative to historical customer commodity rates, then there is value for customers in providing stable, low-priced supply at those price levels into the future.

The second market price perspective is to compare the acquisition price or forward market price to a price forecast (and understand the assumptions for the forecast). The third is to compare natural gas supply costs relative to alternative energy sources, such as natural gas prices versus crude oil prices. The price relationship is important in terms of producers' choices to allocate capital to oil and liquids versus natural gas. It is also relevant for international LNG pricing, where some formulas use a crude oil measure. Another interesting price comparison is natural gas to diesel fuel, as it relates to switching from diesel to LNG in the transportation sector.

Fourth, the market price should be compared to the "break-even" cost of production. Market price rarely trades below the cost of production for a sustained period of time, for if the price falls below production cost, production will slow or cease and there will be scarcity of supply after any surplus has been used up. At the same time, the market price rarely stays above the full embedded replacement cost for all production zones. When prices are high enough for the most producers to invest capital and earn an attractive return, producers tend to respond to the market price signal and will commence drilling and production.

The fifth and final consideration is to track the commodity flow of natural gas from discounted-price markets to premium-priced markets. It is helpful to see how one market price compares to other markets in relative terms in order to determine whether it is under or over-valued (a purchaser wants to acquire an under-valued asset). Comparing U.S. natural gas prices relative to global gas prices is important for understanding this driver. Taken together, these price parameters give a context for a long-term hedge's relative price value.

A. Historical Context

Historical price analysis can provide a context for forward market prices. Currently, natural gas prices are very low, compared to historical prices. The graph shows the Base Case Price (green line) and the Illustrative Reserves price (red line). The Base Case Price is the average of [redacted] This is a steadily increasing Henry Hub market price from 2015 to 2035[17]: The Illustrative Reserves Price is a theoretical price provided by BHUH, representative of a potential reserves acquisition where the drilling efficiencies over time exceed the rate of inflation.

Figure 28 – Historical and Forward Market Natural Gas Prices (Nominal Prices)

[redacted]

In the graph above, the blue line is the historical monthly Henry Hub Natural Gas for January 1997 to June 2015 reported by EIA. The red line represents prices for 2016 forward from the Henry Hub Base Case Price used in Aether's model. The green line represents the Illustrative Reserves Price, adjusted to be a Henry Hub price equivalent.

17 [redacted]

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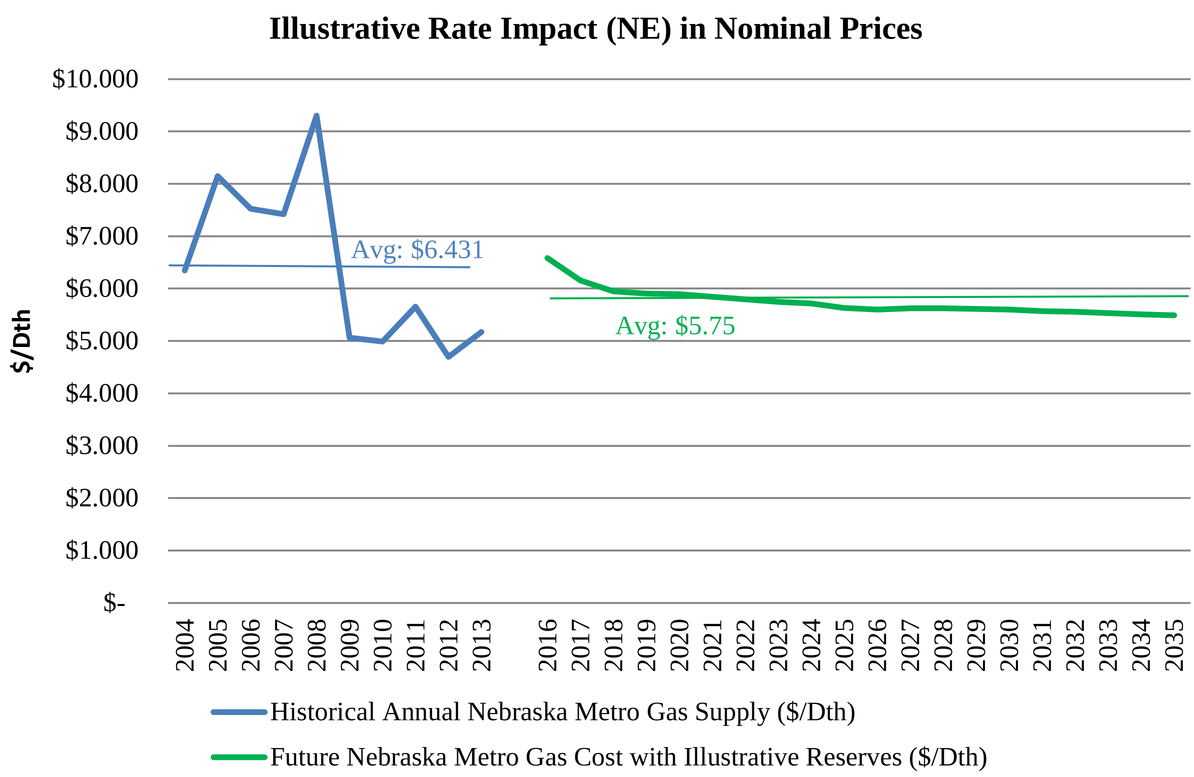
B. Customer Rate Impact

To consider the gas supply cost impact of acquiring gas production, Aether looked at the impact to customers for one of Black Hills utilities (Nebraska gas utility). Aether compared the historical cost of gas supply to a projected forward cost based upon the Illustrative Reserves Price scenario. The graph below shows the historical annual gas supply costs for Nebraska gas customers served in metropolitan areas ("Nebraska Metro Gas Cost"). This data was provided by BHUH for the period of 2004-2013. Aether simulated forward gas supply costs, by adjusting the Illustrative Reserves Price to a Nebraska Metro Gas Cost equivalent. [18]

Figure 29 – Customer Rate Impact (Historical and Future)



[18] To develop the pricing differentials, first Aether reviewed the historical price differential between the Nebraska Metro Gas Cost and the wholesale market hub Ventura. Aether applied this differential and the regional forward price spread in its model between the Illustrative Reserves and Ventura, to simulate the forward gas supply cost for Nebraska Metro Gas Cost.

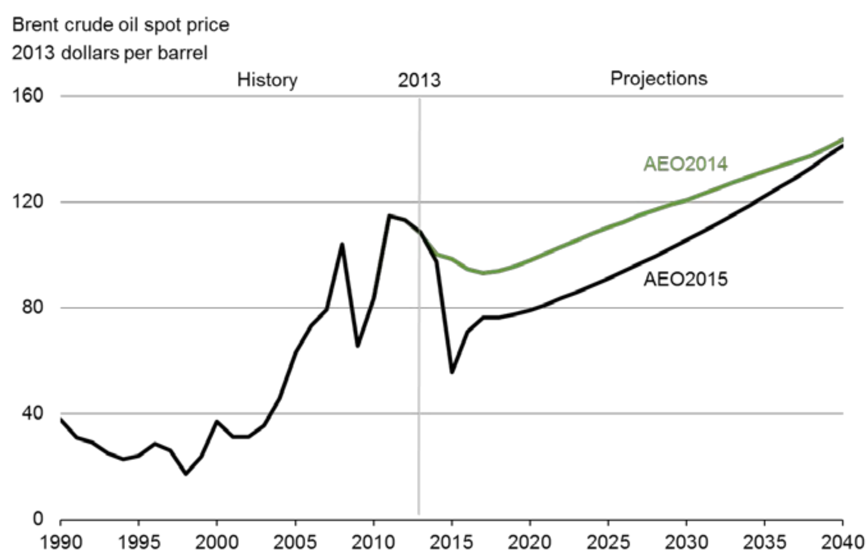
The analysis indicates that hedging twenty years into the future would result in an average cost that would stabilize gas supply costs at attractive levels for customers.

C. Natural Gas to Crude Oil Price Comparison

In addition to looking at natural gas forecasts from different sources and using different assumptions, it can be helpful to look at natural gas prices relatve to oil prices. There are several reasons for comparing natural gas and crude oil prices. Producers have some flexibility in whether to drill for natural gas, natural gas liquids, or crude oil. Comparing the North American gas prices to crude oil prices helps explain the shift from gas production to more crude oil drilling. In recent years, the U.S. and Canada produced more crude oil together than any Middle East producer including Saudi Arabia.

EIA has forecasted lower crude oil prices in the 2015 EIA AEO compared to its Annual Energy Outlook 2014, but over time both forecasts reach $135 /bbl price by 2030. Additionally, the AEO 2015 forecast shows market price recovery to approximately $80 /bbl in the next four to five years:

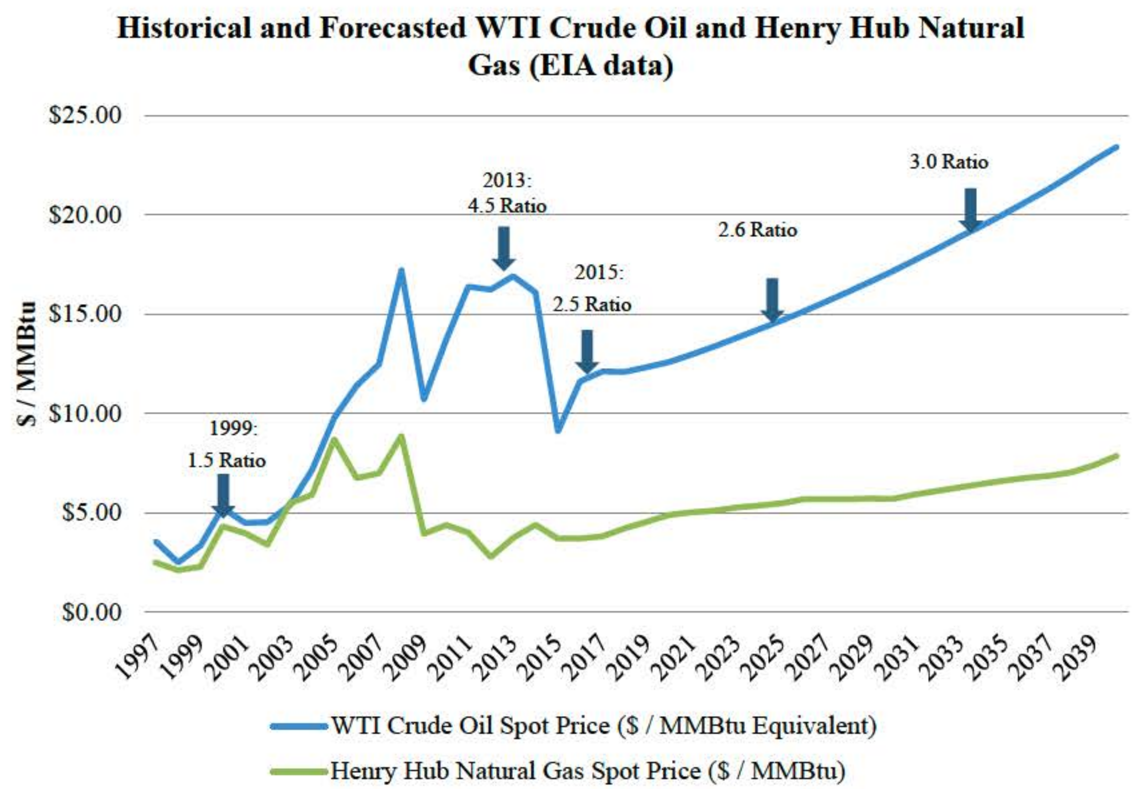
Figure 30 – EIA Crude Oil Price Forecast[19]



[19] U.S. Energy Information Administration, Center for Strategic and International Studies, *AEO2015 Rollout Presentation*, Adam Sieminski, Administrator, April 14, 2015

The figure below illustrates EIA's historical and forecasted prices of natural gas and crude oil. The crude oil price has been divided by 5.8 to put the price per barrel into a price per MMBtu equivalent. Historically, the price relationship widened to where crude oil was 4.5 times the value of natural gas in 2013, but that narrowed to 2.5 times in 2015. But the forecasts show the price relationship widening again both in absolute terms and as a ratio going forward. This may influence producers toward more oil production and would support LNG priced off of crude oil formulas.

Figure 31 – EIA: Natural Gas and Crude Oil Price Comparison



Aether concluded that the theoretical Illustrative Reserves price would be an attractive price level at which to hedge long-term gas supply costs for customers if it could be executed. The Illustrative Reserves Price compared favorably to historical wholesale market prices and to the Base Case Price. Additionally, the estimated forward gas supply costs for customers associated with the Illustrative Reserves Price offered gas supply cost stability and was attractive in terms of the price level with historical gas supply costs. Lastly, EIA forecasts that natural gas will remain discounted to oil prices in the future. In the following sections, Aether will identify supply-demand factors that impact North American gas prices. These are examples of fundamental market drivers to consider in the context of long-term hedging.

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Supply Factors

To supplement the pricing analysis in the prior section, Aether examined the future supply trends to ascertain if economic indicators supported continued supply growth. Shale gas plays have emerged as the lowest cost source of gas and shale drilling is growing as a percent of U.S. gas supply, but still represents only ~40%. Canadian production has been declining in recent years, which has reduced exports to the U.S. The decrease in Canadian gas imports has not posed problems to date since domestic supply gains made up for the decrease in imports. But, in the future, if demand exceeds supply, the U.S. market may not rely on Canadian imports as it did a decade ago, unless prices rise to levels to encourage new drilling in Canada.

Another set of supply factors relates to producers' economics. Aether's view is that the production trends are stable, but producer profits are not large. Producers are reducing natural gas drilling capital budgets in absolute terms and/or directing capital to oil and liquids-rich investments. Reserve replacements are somewhat higher than annual consumption but not overwhelmingly so. These factors leave some doubt regarding long-term domestic production growth relative to projected demand increases.

A. Production Trends

Shale gas technology substantially increased in the amount of recoverable North American gas supply. While conventional plays in the Gulf of Mexico, in the Western Sedimentary Basin, and in Nova Scotia are in decline, new gas fracturing technology enabling producers to access vast supplies of shale gas has more than compensated for the reduction. New technology that provided lower cost access to shale gas caused total U.S. production to grow substantially from 2005 to 2013. The largest shale production areas have been the Marcellus Shale and Barnett Shale. The graph below from the Energy Information Administration (EIA) demonstrates this phenomenon.

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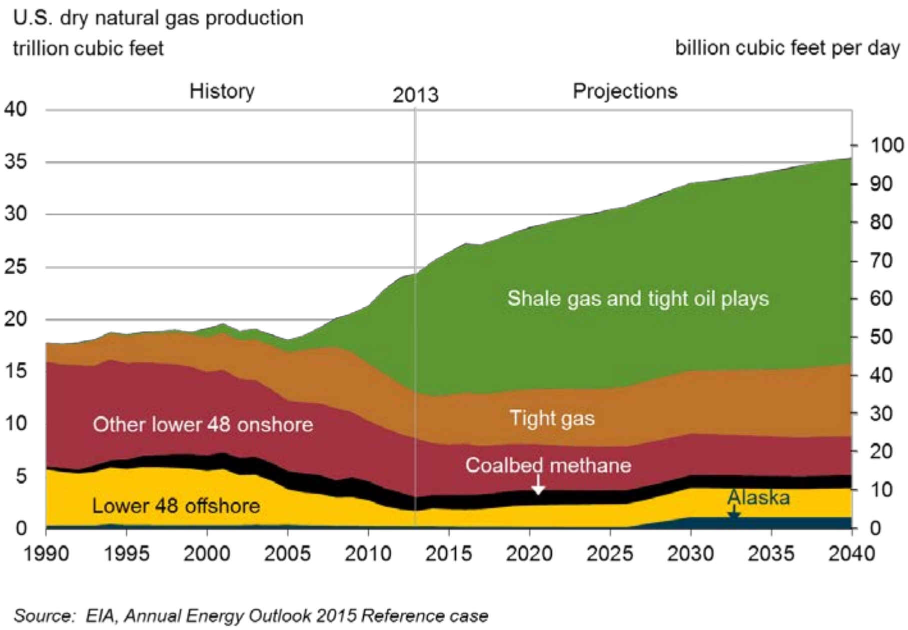
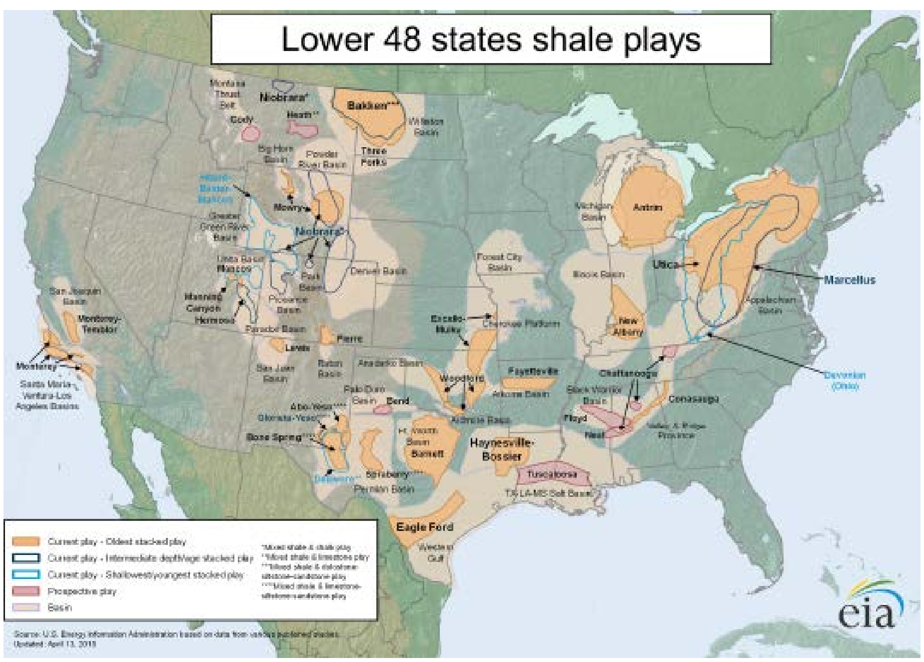
Figure 32 – EIA U.S. Shale Gas [20]



Below is a map illustrating the primary Lower 48 states; shale gas production areas.

Figure 33 – Shale Gas Production Areas



[20] U.S. Energy Information Administration, Center for Strategic and International Studies, *AEO2015 Rollout Presentation*, Adam Sieminski, Administrator, April 14, 2015

Since shale gas currently represents approximately 40% of U.S. gas production, shale gas production economics are important to understand. Because the shale gas is growing materially in its contribution to total natural gas production and because it has the lowest extraction cost, an analysis of break-even production costs can help define a long-term anticipated floor to market prices.

B. Break-Even Production Costs

The table below in Figure 34 provides a list of variable and fixed costs. Both are part of the long-term break-even production cost calculations. Typically when a producer is contemplating shutting-in production because prices have fallen, the variable costs are more relevant.

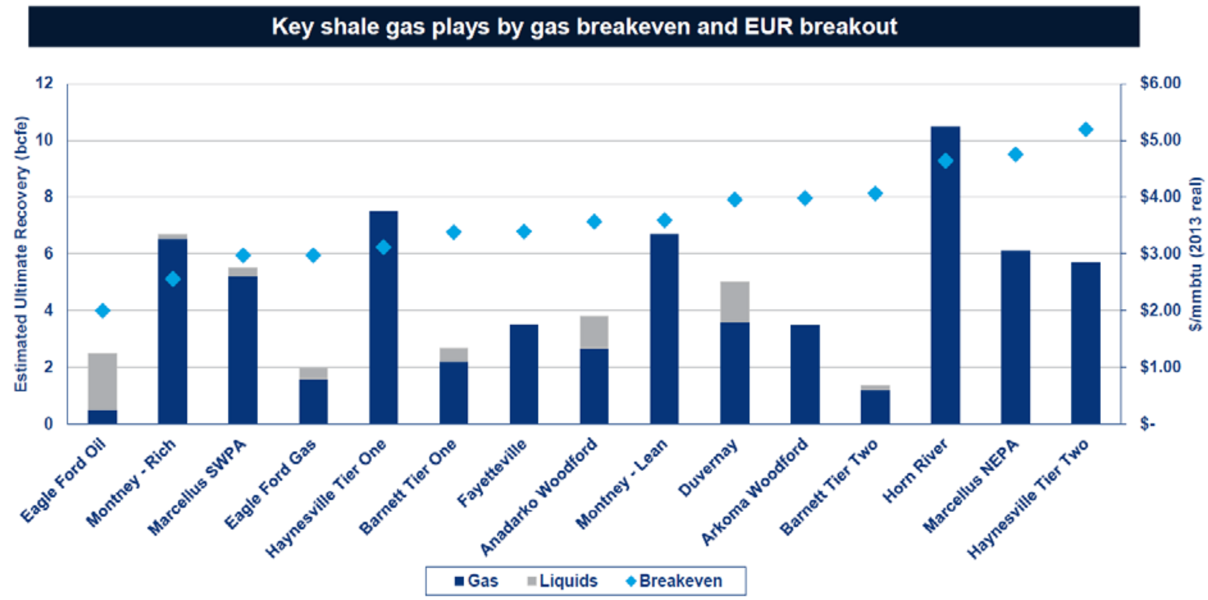
Figure 34 – Natural Gas Production Variable and Fixed Costs

Variable Costs	Fixed Costs
Lifting costs	Land lease cost
Processing costs	Drilling Permits
Field gathering costs	Equipment costs
Transportation to a market hub	Development and drilling costs
Taxes and royalties	Well completion costs
Labor	Waste disposal
	Pipeline interconnection costs
	General & administrative costs
	Financing costs

In May 2014, Wood Mackenzie's analysis of the major shale plays in North America illustrates break-even prices of $3.00 - $5.00 per Mcf for these low cost shale gas resources.[21] The break-even price per shale region is mapped in the blue diamonds below. The bar charts show the amount of recoverable reserves ("Estimated Ultimate Recovery").

[21] David Pruner, Senior Vice President, Wood Mackensize, *North American Natural Gas Market and the Shale Revolution*, May 19, 2014

Figure 35 – Breakeven Shale Gas Prices



Sources: Wood Mackenzie (North America Gas, Unconventional Gas, and Upstream services)

GARP Global Association of Risk Professionals

C. Imports

In Canada, Horn River and Montney shale plays in western Alberta and northern British Columbia have opened new areas of production opportunity. But, unlike in the Lower 48 United States, the shale production coming from these areas has not been able to overcome declines in conventional Canadian production. Canada's National Energy Board ("NEB") forecasts continued declining production over the next few years, and then recovery in production driven by shale gas production increases resulting from higher market prices. But what is markedly different going forward is that because of growing domestic demand, Canada has less exportable surplus gas to send to U.S. markets if it were needed as illustrated in the figure below:

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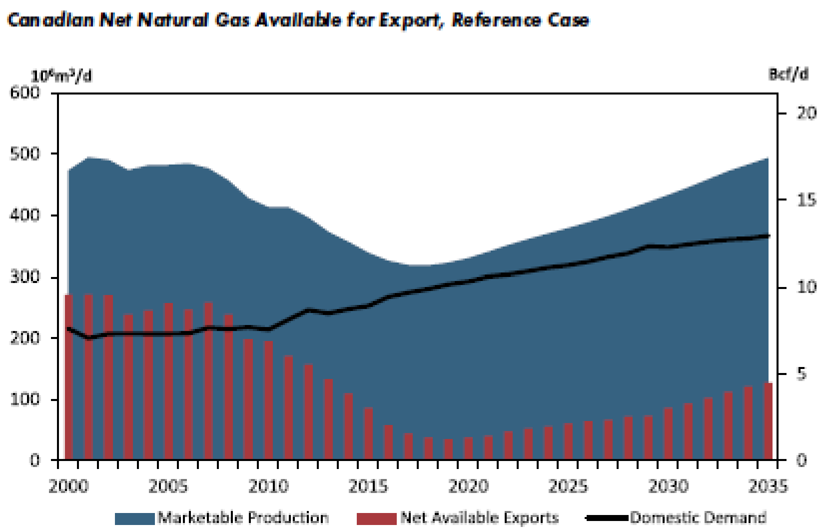
Figure 36 – Canadian Marketable Gas Production[22]



While the U.S. has historically received a large number of natural gas exports from Canada, this has not been the case in recent years. Fortunately U.S. shale gas production has been available to off-set the declines in Canadian gas exports. But this does mean that Canadian imported gas is not as reliable as a back-up supply if demand for U.S. natural gas begins to exceed domestic production levels.

In its forecast for 2015-2017 natural gas production trends, the Canadian National Energy Board described the current North American gas market as "oversupplied" but pointed out a couple of trends. While 2014 Canadian gas production had increased approximately 4.8% from 2013 levels, it is still below the 2005 peak. The report notes that the decline in global oil prices impacted natural gas production negatively: "*The decline in oil prices since mid-2014 has impacted the North American gas market in the form of reduced revenues, constrained cash flows and significantly less gas-targeted drilling*." The report also notes the decline in the market prices of natural gas liquids such as ethane, propane and normal butane is reducing producer margins: "*Previously, the attractive price spread between natural gas and natural gas liquids (NGLs) promoted NGL-targeted drilling and the natural gas price was of less consequence. Rising NGL deliverability is creating a supply glut in Canada and the U.S. and the oversaturated market for key NGLs (ethane, propane, butane) is leading to lower NGL prices and reduced producer revenues*." [23]

[22] National Energy Board, *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, November 21, 2013, 55.
[23] National Energy Board, *Short-Term Canadian Natural Gas Deliverability 2015-2017*, An Energy Market Assessment June 2015, 1 and 5.

D. Producer Investment Analysis

With respect to production trends, it can be helpful to track producer margins. In Canada, natural gas producers report a financial metric called "netback", a gross margin comprised of sales price minus royalties, production costs, and transportation expenses. U.S. producers do not regularly publish a similar metric, so the Canadian producers' reporting serves as a proxy for the broader North American producers.

The producers in the table below group their natural gas properties into different geographical locations. Looking at the trends in their netback margins is helpful for viewing trends over time. From the period of 2008 to 2014, the group's netback margins were highest in 2008 and then dropped to lows in 2012. For most of the group below, the margins have been a little better in 2013-2014, but still the netback margin is significantly below the 2008 levels.

Figure 37 – Canadian Producer Netbacks

Canadian Producer	Gas Production Location	2014	2013	2012	2011	2010	2009	2008
Encana	US	$1.77	$2.02	$3.24	$3.43	$3.94	$2.13	$5.90
Talisman	N America	NA	$1.66	$0.98	$2.51	$3.11	$2.59	$4.63
Canadian Natural Resources	All	$2.70	$1.70	$1.04	$2.50	$2.79	$3.13	$5.91
Cenovus	Canada	$2.89	$1.87	$1.18	$2.30	$2.88	$3.01	$6.56
Husky Energy	Western Canada	$2.68	$1.68	$1.32	$2.43	$2.21	$1.97	$5.02
Suncor	N America	NA	NA	$1.88	$2.55	$2.76	$2.39	$5.58

Monitoring trends in producers' return on equity is helpful for examining the impact of low gas prices. The table below in Figure 38 shows the return on equity percentage for a group of peer independent natural gas producers. Producers can have a different capital structures, making comparisons between producers difficult. But the metric is helpful for seeing how the producer peer group is very clearly impacted by natural gas price. The Henry Hub natural gas price is provided at the bottom of the table to allow for comparison to producers' return on equity to the underlying commodity price:

Figure 38 – Producers' Return on Equity (%)

Large Independent North American Gas Producers Peer Group

Return on Equity (%)

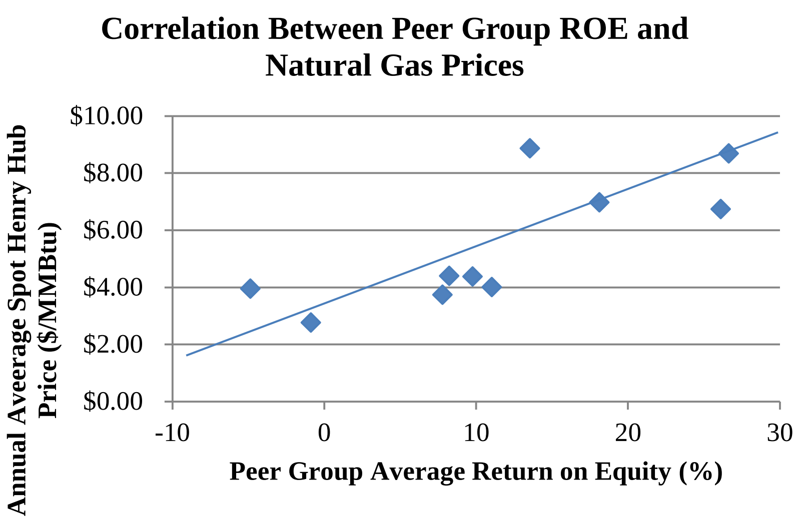
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Anadarko Petroleum	24.47	37.6	24.2	18.6	(0.7)	3.8	(13.7)	12.4	3.8	(8.4)
Antero Resources Corporation							20.1	(15.7)	(0.7)	16.9
Apache Corporation	28.2	21.6	19.8	4.5	(1.8)	15.4	17.7	6.7	6.9	(18.2)
Cabot Oil & Gas	28.1	41.6	16.6	14.8	8.2	5.6	6.2	6.2	12.9	4.8
Chesapeake Energy Corp	24.2	27.4	12.0	4.6	(43.7)	14.4	12.2	(7.2)	3.7	9.5
Devon Energy Corp	20.5	17.6	18.2	(11.0)	(15.2)	26.1	23.1	(1.0)	(0.1)	7.7
EQT Corp	42.3	33.9	25.2	16.2	7.5	8.7	14.4	5.1	10.2	9.0
EOG Resources Inc.	35.5	26.4	17.3	30.5	5.8	1.6	9.5	4.4	15.3	17.6
Range Resources	17.6	16.3	15.5	16.5	(2.2)	(10.4)	2.5	0.6	4.9	21.2
Southwestern Energy Co.	19.0	12.8	14.4	27.3	(1.5)	22.8	18.4	(20.2)	21.1	22.3
Peer Group Average	26.6	26.1	18.1	13.6	(4.9)	9.8	11.0	(0.9)	7.8	8.2
Henry Hub Average Price $/MMBtu	$8.69	$6.73	$6.97	$8.86	$3.94	$4.37	$4.00	$2.75	$3.73	$4.39

Financial data source: Morningstar

Henry Hub data source: EIA

The peer group's average profitability metric of return on equity (%) relates to the level of natural gas prices. Figure 39 illustrates how the profitability measure of return on equity correlates to the annual average natural gas price (represented as the Henry Hub price).

Figure 39 – Correlation between Natural Gas Price and Producer Profitability



While netback margins and return on equity percentages provide a historical and current perspective of the relative profitability in natural gas production, looking at producers' capital budgets provides a forward perspective of where exploration and production companies are making future investments. With the decline in oil and gas prices in 2014, there has been a reduction in exploration and production spending. This is supported by an analysis conducted by *Oil & Gas Journal*, comparing 2015 capital investment in different energy sectors to 2014 and 2013 levels. U.S. exploration and production capital spending is forecasted to decline 32% from 2014 levels (which had increased 9% from 2013). Canadian activity is forecasted to decline 30% from 2014 levels (which had increased 7% from 2013):

Figure 40 – U.S. and Canadian Capital Investments[24]

WHERE FUNDS WILL GO FOR US PROJECTS

Table 1

	2015, million $	2015-14 change,%	2014, million $	2014-13 change,%	2013, million $
Exploration-production					
Drilling–exploration	170,202	–32.0	250,202	9.3	228,948
Production	32,338	–32.0	47,538	9.3	43,500
OCS lease bonus	700	–27.1	960	–21.3	1,220
Subtotal	**203,240**	**–32.0**	**298,700**	**9.1**	**273,668**
Other					
Refining and marketing	13,350	2.0	13,094	–0.8	13,200
Petrochemicals	6,500	8.3	6,000	53.8	3,900
Crude and products pipelines	23,000	–3.1	23,731	43.9	16,489
Natural gas pipelines	9,000	2.6	8,769	–4.4	9,169
Other transportation	2,400	–12.7	2,750	52.8	1,800
Miscellaneous	4,500	–6.3	4,800	4.3	4,600
Subtotal	**58,750**	**–0.7**	**59,144**	**20.3**	**49,158**
Total	**261,990**	**–26.8**	**357,845**	**10.8**	**322,826**

[24] Bob Tipee, Oil & Gas Journal, *Companies slash capital budgets as oil price drop cuts cash flows,* April 6, 2015,Volume 113.4, p 28-34.

CANADIAN SPENDING PLANS Table 2

	2015, million $ (Can.)	2015-14 change,%	2014, million $ (Can.)	2014-13 change,%	2013, million $ (Can.)
Exploration–production					
Drilling–exploration	20,590	–30.4	29,598	6.6	27,774
Production	11,410	–30.4	16,402	6.6	15,391
Subtotal	**32,000**	**–30.4**	**46,000**	**6.6**	**43,165**
Oil sands*	**26,000**	**–21.2**	**33,000**	**7.1**	**30,809**
Other					
Refining and marketing	2,950	–1.7	3,000	30.4	2,300
Petrochemicals	1,280	6.7	1,200	50.0	800
Crude and products pipelines	3,100	–11.4	3,500	3.9	3,368
Natural gas pipelines	2,200	37.5	1,600	40.2	1,141
Other transportation	465	–12.3	530	32.5	400
Miscellaneous	750	–8.5	820	5.1	780
Subtotal	**10,745**	**0.9**	**10,650**	**21.2**	**8,789**
Total	**68,745**	**–23.3**	**89,650**	**8.3**	**82,763**

*In situ, mining, and upgrading.

For large independents that have chosen to focus on natural gas production, capital is being spent in the lowest cost producing areas, chiefly in shale plays. For example, Chesapeake Energy, the second largest natural gas producer has operations in the Powder River Basin and Anadarko Basin and 71% of their production is natural gas with the balance of the production in natural gas liquids and oil. Their 2015 capital budget is reduced 45% from the 2014 capital budget. Most of the drilling activity is in the Eagle Ford, Haynesville, and Utica shales. In their February 2015 outlook they had expected to have 35-45 average operating rigs over 2015. This was reduced to 9-19 rigs by year end in the May 2015 outlook.[25] Similarly, Range Resources the eleventh largest U.S. natural gas producer is devoting 95% of its capital budget in the Marcellus shale and only 5% in Midcontinent and other holdings.[26] Range showed its drilling costs have dropped 61% since 2011 and well completion cost has declined 66%, making it a low cost producer.

Producers' focus on low cost Mid-Atlantic and Appalachian shale drilling is bringing more production to market in those areas. But the gas is isolated because of a lack of take-away pipeline infrastructure. While the activity in Marcellus and other nearby shales is adding reserves, the impact is regional, until more pipeline capacity is added to move the gas to other markets. Therefore, the benefit of shale production may be felt more regionally than nationally.

In the past few years, a number of natural gas producers reduced capital investment in natural gas exploration and production in order to allocate more capital to crude oil and natural gas liquids production. This trend began to emerge in 2013 and continues today despite the drop in

[25] Chesapeake Energy, *Leadership, Performance And Value*, UBS Global Oil and Gas Conference, May 19, 2015
[26] Range Resources, *Company Presentation*, June 3, 2015

global crude oil prices mid-2014. Excerpts from a number of exploration and production companies' investor presentations highlight the industry's focus on crude oil and liquids-rich natural gas as opposed to dry natural gas. In a May 2015 investor presentation, Devon Energy (sixth largest U.S. natural gas producer) described its asset portfolio as "oil driving production growth". Its strategy is to focus on four major oil plays in Alberta, Rockies, Permian and Eagle Ford and on two "liquids-rich" natural gas plays in the Anadarko Basin and the Barnett Shale. 82% of their 2015 capital budget is devoted to the four oil plays.[27]

Even though EOG Resources is the fourteenth largest natural gas reserve holder in the lower 48 states, in its investor presentation May 27, 2015 at the Sanford Bernstein Strategic Decisions conference, EOG Resources' CEO presented only the company's oil strategy. Because of greater operating efficiencies (lower drilling costs per well and shorter drilling time per well), its operating margins today are better than in 2012. The presentation illustrated increasing oil production in 2014-2015, reducing production operating costs, increasing drilling density, and adding drilling locations that can produce attractive margins even at a low oil price.

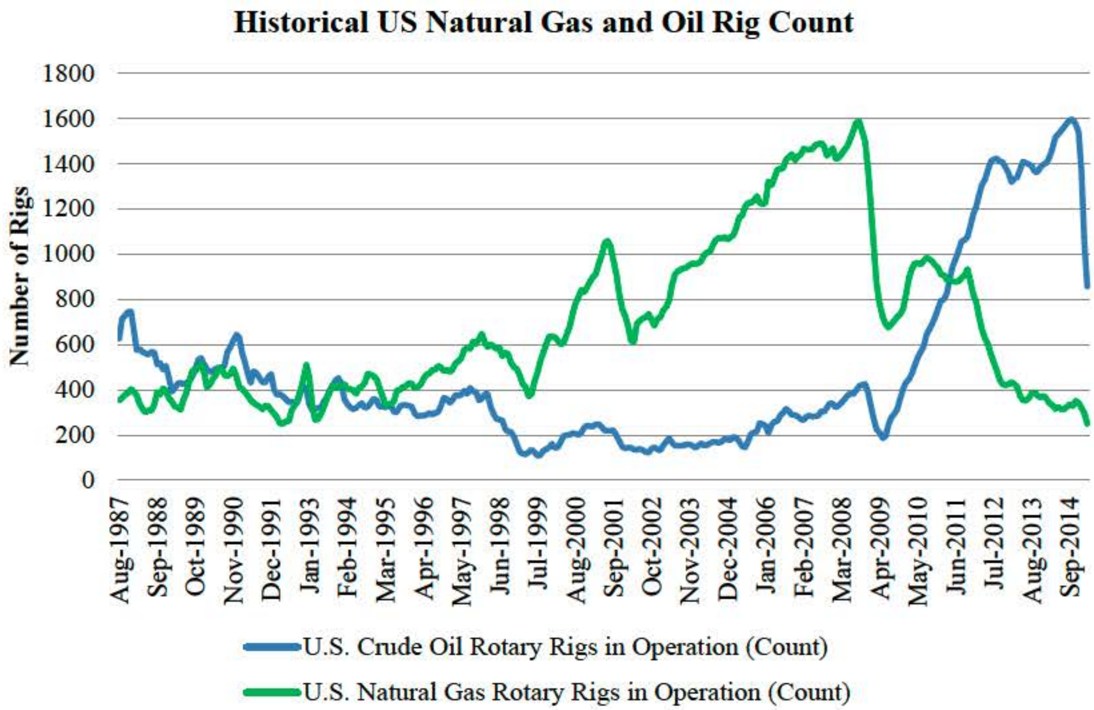
In a June 2015 corporate presentation, Encana reported 80% of its 2015 capital budget is focused on four shale plays – Montney (liquids-rich natural gas), Duvenay (high value condensate), Permian (oil), and Eagle Ford (oil) – demonstrating a commitment to oil and liquids plays. The presentation stated that the estimated oil netback was $26 /bbl compared to only $1.10/Mcf for natural gas.[28] (At a 5.8 conversion rate barrel to Mcf, the oil netback would be approximately $4.80 per Mcf.) Despite the decline in global oil prices, Encana has chosen to focus on oil and liquids-rich properties to be well-positioned for a rise in oil prices.

E. Rig Counts and Reserve Replacement

There is empirical evidence illustrating the shift in recent years from natural gas drilling to oil drilling. First, examining the number of rig counts allocated to oil and gas production shows shifting exploration and production trends. The number of rigs devoted to natural gas drilling has declined steadily since 2009 while oil-directed rigs have steadily increased.[29] And in 2015, rig counts for both oil and natural gas have declined. This is in part due to increased efficiency in horizontal drilling, where fewer rigs would be required today than a decade ago to produce the same amount of natural gas. The decline in the number of rigs corroborates producers' announced reductions in capital directed to gas drilling.

[27] Devon Energy, *Conference Presentation*, UBS Global Oil and Gas Conference, May 19, 2015
[28] Encana Corporation, *Corporate Presentation*, June 2015
[29] EIA, Crude and Natural Gas Rigs, http://www.eia.gov/dnav/ng/ng_enr_drill_s1_m htm (Accessed June 2015)

Figure 41 – Rigs Dedicated to Natural Gas and Crude Oil Drilling



Reserve replacement is a metric to track the industry's capital investment and commitment to maintaining, increasing or decreasing investment in crude oil and natural gas reserves. If returns are attractive, reserve replacements tend to be steady or increasing. In contrast, when investment returns are unattractive, there would be tendency for reserve replacement to decline. For example, when oil prices traded in a range of $80 to $120 during the two year period of 2011 to 2013, reserve replacements through 2013 reflect this market price strength[30], and the 3-year replacement history exceeded the 5-year replacement history:

Figure 42 – Crude Oil and Natural Gas Production Replacement Ratio

Production replacement rates

Oil

US – oil production replacement rates (a)

	2009	2010	2011	2012	2013	3-year	5-year
All sources	168%	243%	246%	268%	216%	242%	229%
Excluding purchases and sales	161%	215%	240%	265%	222%	241%	222%

(a) Includes the 50 largest companies based on 2013 end-of-year oil and gas reserve estimates. Activity related to acquired companies has also been reflected as described on page 1.

[30] Ernst & Young, *US Oil and Gas Reserves Study 2014*, EY American Oil & Gas Services, 2014, p 6.

But the opposite scenario will develop when prices decline. While oil prices were increasing 2011 through early 2014, North American spot natural gas prices were trending lower, going below $2.00 at Henry Hub during summer 2012. While oil production replacement grew at a significant rate, this is not the same case for natural gas production replacement. In fact, in 2012, when gas prices hit recent low levels, production replacement was negative. And the three-year production replacement for natural gas is less than the five-year production replacement. [31]

Production replacement rates

Gas

US – gas production replacement rates (a)

	2009	2010	2011	2012	2013	3-year	5-year
All sources	160%	268%	181%	(34%)	210%	118%	153%
Excluding purchases and sales	167%	263%	189%	(17%)	229%	133%	163%

(a) Includes the 50 largest companies based on 2013 end-of-year oil and gas reserve estimates. Activity related to acquired companies has also been reflected as described on page 1.

While the natural gas production replacement has been positive, it should be monitored since the three year trend has been at a lower replacement rate than the five year trend. Many long-term price forecasts assume that future production will be enough to meet demand, but production replacement must continue to grow for that to occur.

Domestic Demand

When natural gas prices are low, new demand will likely emerge. In order to anticipate potential demand, it is helpful to look at where new demand may emerge from and the scale of it. From a demand perspective, when a commodity source is fully priced to move into premium markets and when it is low enough in cost to be a viable substitute for another energy source, then it likely under-valued and the price will re-adjust. And, other factors can also create demand for natural gas, such as regulatory requirements or changing public tastes and trends.

Aether examined gas demand growth in electric generation, transportation demand, and LNG exports. There is always some uncertainty in forecasting future natural gas demand because certain conditions must be present for the demand to materialize, such as infrastructure to serve demand, commercial feasibility of projects, rate of economic growth among other factors. Given the price advantage that U.S. natural gas has compared to oil price, diesel price, and international gas prices, industry commitments to new infrastructure, and evidence of commercial feasibility,

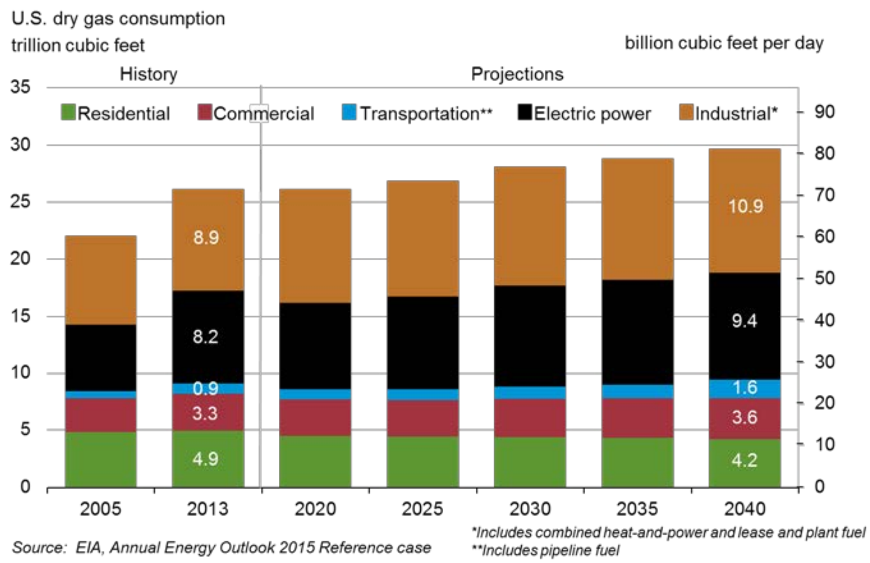
[31] Ibid, 7.

there may be more demand growth than what is projected in [redacted]

A. Gas For Generation

Figure 43 below illustrates gas demand growth assumptions in EIA's reference case. The demand occurs in all sectors except the residential sector, where energy efficiency initiatives are expected to reduce natural gas demand over time:

Figure 43 – EIA 2015 Reference Case Natural Gas Demand[32]



To put the natural gas demand for electric power into a broader electricity context, the graph below shows growth in electricity production by fuel type. Natural gas and renewable energy show the highest growth, with reductions occurring chiefly in coal demand:

[32] U.S. Energy Information Administration, Center for Strategic and International Studies, *AEO2015 Rollout Presentation*, Adam Sieminski, Administrator, April 14, 2015

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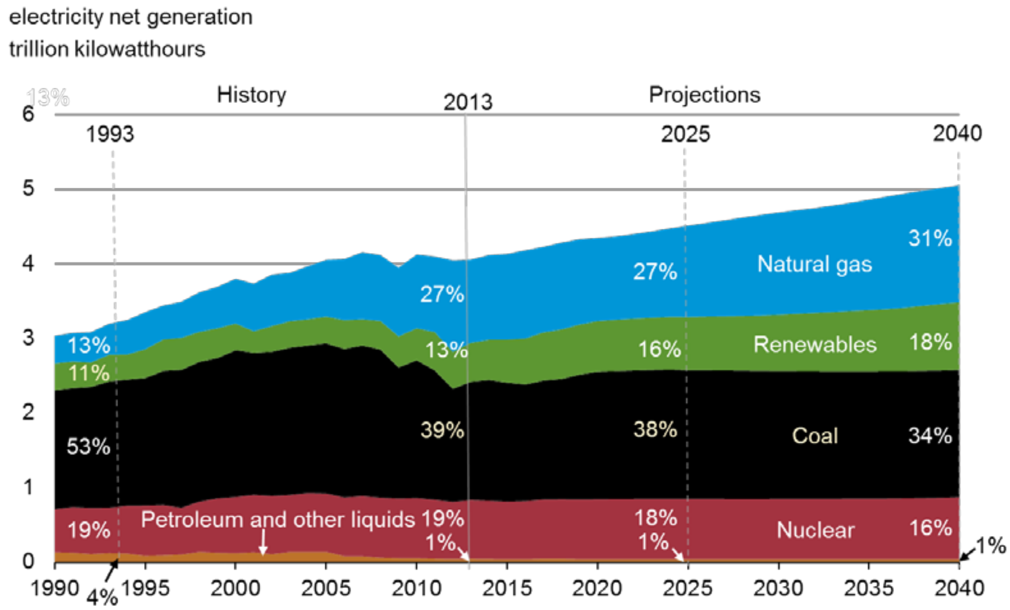
Figure 44 – EIA AEO2015 Electricity Generation by Fuel Type[33]



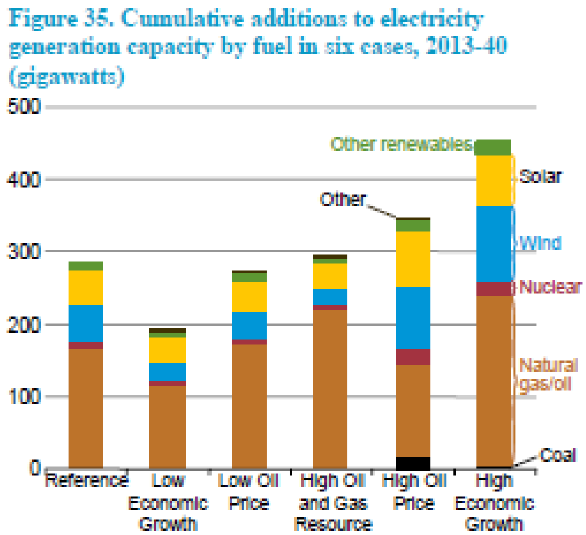
Source: EIA, Annual Energy Outlook 2015 Reference case

Since 1993 to 2013, the biggest growth in generation fuel has been in natural gas, with the reduction occurring in the coal sector. From 2013 to 2025, the largest growth is forecasted to occur in renewable energy, with gas maintaining its current share but not increasing in percentage of the total until closer to 2040.

EIA provided forecasts for gas generation under several different scenarios in its AEO2015, three of which are greater than what EIA has included in its Reference Case (the Low Oil Price case, High Oil and Gas Resource case, and High Economic Growth case):

[33] Ibid.

Figure 45 – EIA's Different Scenarios for Generation by Fuel[34]



The largest growing gas demand sector is electric power generation. Due to the FERC's 2015 final rule to improve gas-electric coordination, there will likely be more efficient dispatch of gas-fired generation. The Commission approved changes to pipeline nominations that should more closely align the natural gas industry and power industry scheduling procedures, thereby facilitating more efficient gas plant dispatch, resulting in higher capacity utilization. As a result, not only is gas generation capacity growing, but energy production from gas generation should increase through improved dispatch efficiency.

As a result of stringent EPA regulation[35] to limit emissions from stationary sources, there is significant pressure on generation owners to close old, inefficient coal plants. There have been several recent regulatory developments regarding EPA's regulation of emissions. The examples below illustrate the complexity of the issues and the level of litigation involved. Some of the recent developments reinforce EPA's ability to regulate emissions, while others challenge it. But most electric generation forecasts anticipate continued closure of coal capacity and new additions in gas generation and renewable energy because of regulatory activity to date.

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[34] Energy Information Administration, *Annual Energy Outlook 2015 With Projections to 2040*, DOE/EIA-0383(2015), April 2015, 26.

[35] This includes several forms of regulation: National Ambient Air Quality Standard, Mercury and Air Toxics Standard, Clean Air Mercury Rules and Clean Air Interstate Rules.

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Cross-State Air Pollution Rule Supreme Court Decision

On April 29, 2014, in a 6-2 decision the Supreme Court upheld the United States Environmental Protection Agency's (EPA) authority to impose regulation on sulfur dioxide, nitrogen oxides, ozone, and fine particle emissions that flow north and east from 28 states ("Cross-State Air Pollution Rule" or CSAPR) in EPA v. EME Homer City Generation. The U.S. Court of Appeals for the D.C. Circuit had rejected EPA's Clean Air Interstate Rule (CAIR) in 2008, after which EPA developed CSAPR as a replacement rule in 2011.[36] In 2012, the D.C. Circuit court had vacated CSAPR. The lower court had determined EPA had not provided states an adequate opportunity to develop state implementation plans (SIPs), but the Supreme Court's supported EPA's imposition of a "federal implementation plan" (FIP). The Supreme Court's decision was a significant victory for EPA. The case will be remanded to the D.C. Circuit, who can request supplemental briefing and review additional challenges to CSAPR that were not available for its initial decision. EPA will likely need to revise some of the original regulation and develop updated implementation dates.

EPA Ability to Regulate Greenhouse Gas Emissions Supreme Court Decision

In a June 23, 2014 decision confirming EPA's jurisdiction to allow EPA to regulate greenhouse gas emissions from existing power plants, Utility Air Regulatory Group v. EPA, the U.S. Supreme Court determined that once a source is subject to Prevention of Significant Deterioration (PSD), the source then "must comply with emissions limitations that reflect the 'best available control technology' or (BACT) for "each pollutant subject to regulation under' the Act." [37] Under EPA's approach, a source that becomes subject to PSD would also be subject to EPA's greenhouse gas permitting process and BACT requirements. The EPA's recent Clean Power Plan applies to existing power plants, which would be subject to PSD.

EPA Mercury and Air Toxic Standards Rule

On June 29, 2015 the U.S. Supreme Court ruled the EPA had erred by not considering costs when it issued the 2011 Mercury and Air Toxic Standards Rule. The decision was not about the agency's ability to regulate emissions but about the EPA's cost accounting procedure. The decision effectively halts the implementation of the rule. But many electric utilities had already taken steps to comply with the rules given the upcoming 2016 deadline, so the impact of the decision may be muted.

[36] "The Supreme Court Upholds EPA's Cross-State Air Pollution Rule", Latham & Watkins Environment, Land, and Resources Practice, Client Alert Commentary, May 2, 2014, Number 1684.
[37] "EPA Appears to Have Green Light to Develop Regulations on Utility Power Plant Greenhouse Gas Emissions", Duane Morris LLP, July 1, 2014, http://www.jdsupra.com/post/documentViewer.aspx?fid=7ff26ca0-3817-46f2-9fa9-e116032710f7, accessed July 2014.

EPA Clean Power Plan

On August 3, 2015, President Obama and the EPA announced the final Clean Power Plan to cut emissions from existing power plants. By 2030, the objective is for carbon dioxide (CO2) emissions from the power sector to decline by 32% nationwide below 2005 levels. This compares to a 30% reduction in carbon dioxide levels by 2030 in the draft regulation. EPA is establishing carbon dioxide emission performance for stationary electric generating units: fossil fuel-fired electric steam generation and natural gas-fired combined cycle generating units.

States must develop plans individually or together in coordination to achieve the interim targets for 2022-2029 and the final target by 2030. In the final Clean Power Plan, EPA established the best systems of emissions reductions (“BSERS”) as follows:

- **Building Block 1 –** Reducing the carbon intensity of electricity generation by improving the heat rate of existing coal-fired power plants.

- **Building Block 2 –** Substituting increased electricity generation from lower-emitting existing natural gas plants for reduced generation from higher-emitting coal-fired power plants.

- **Building Block 3 –** Substituting increased electricity generation from zero-emitting renewable energy sources (like wind and solar) for reduced generation from existing coal-fired power plants.

EPA applied the building blocks to all coal and natural gas plants in three grid areas: Western Interconnect, Eastern Interconnect and ERCOT. From there it arrived at individual statewide rate-based and mass-based goals, taking into account each state’s particular mix of affected resources.

Each state will have the flexibility to select measures that enable it to meet the statewide rate-based or mass-based carbon dioxide emissions goal. And states can work together to on multi-state approaches such as emission trading platforms. The final rule has a mechanism for states to seek revisions to their plans in the event significant reliability challenges occur, where a power plant is needed to provide critical reliability to the grid. Renewable energy is expected to play a larger role than it did in the proposed plan. But at the same time, the 2030 goal was increased from 30% to 32%. The final impacts are not yet known since states are not required to submit their draft proposals to meet the targets until September 6, 2016, with final plans submitted in 2018. There is a 15 year path to full compliance, with each state demonstrating progress toward meeting the final

2030 target.[38] If states either do not file or refuse to file an emissions reduction plan that meets the requirements, EPA can assign a federal implementation plan (FIP) so they can achieve their emissions targets.

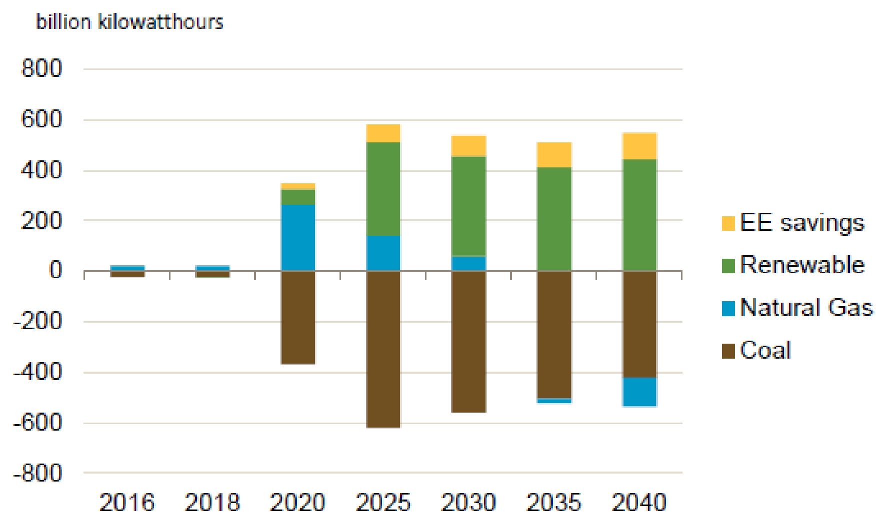
The rule has only recently been released. It appears the rule will put further pressure on coal plant operations, likely resulting in more coal plant closures over and above the effect of previous EPA regulations (such as Maximum Achievable Technology Standards, National Ambient Air Quality Standard, Mercury and Air Toxics Standard, Clean Air Mercury Rules, and Clean Air Interstate Rules). If all goes according to scheduled, the compliance period would begin in 2020.[39] Many industry participants expect there to be a great deal of litigation in response to the regulation, so the schedule may be slower than published.

As noted previously the AEO2015 natural gas price forecasts do not include the effect of the EPA's Clean Power Plan regulation. EIA later modeled the impact of the regulation relative to the AEO2015 Reference case demand by generation type. The figure below shows estimated coal plant reductions from 2016 to 2040. Natural gas generation additions occur primarily in the period of 2020 to 2030:

[38] U.S. Environmental Protection Agency, *Overview of the Clean Power Plan, Cutting Carbon Pollution From Power Plants*,, epa.gov/cleanpowerplan, August 3, 2015
[39] Environmental Protection Agency, *FACT SHEET: Clean Power Plan & Carbon Pollution Standards Key Dates*, http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-carbon-pollution-standards-key-dates (Accessed: June 2015)

Figure 46 – Clean Power Plan: Change in Generation for AEO2015 Reference Case[40]

Figure 4. Change in generation and energy efficiency savings under the Clean Power Plan Base Policy case relative to AEO2015 Reference case



Source: U.S. Energy Information Administration.

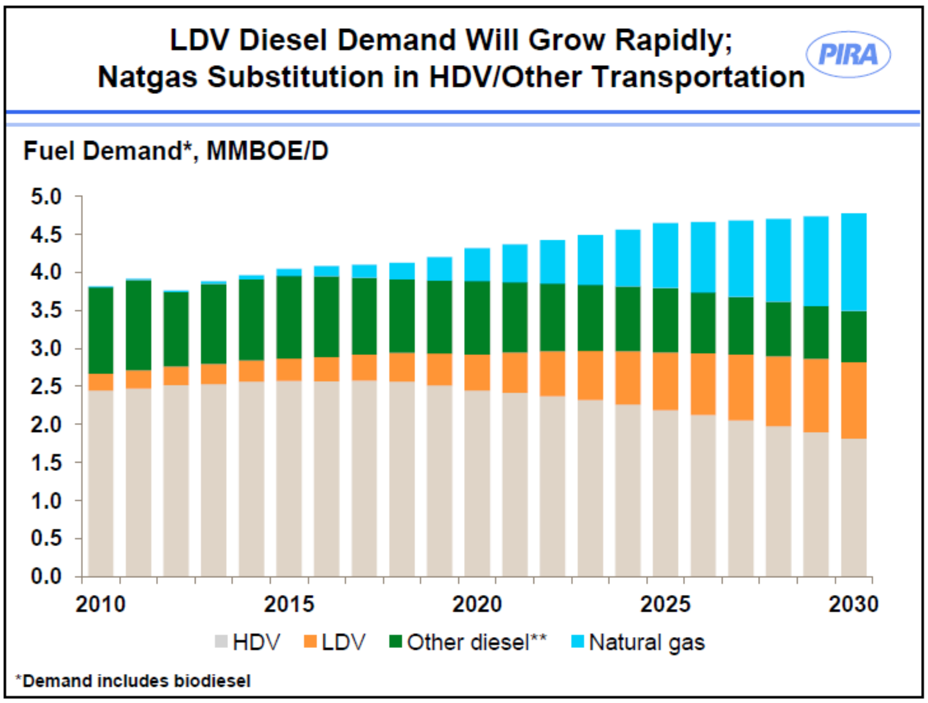
B. Gas As a Transportation Fuel

The smallest but perhaps most interesting potential demand for North American natural gas may be as a domestic transportation fuel. In its AEO2015, EIA forecasts domestic natural gas fuel consumption to grow from .9 Tcf per year in 2013 to 1.6 Tcf by 2040. This means that in 2013, the domestic natural gas transportation fuel consumption represented 3% of domestic demand, and EIA forecasted it will increase 5.5% of 2030 domestic demand. But, in a very different forecast, PIRA Energy Group in September 2014 projected that natural gas could take as much as 1.3 million barrels per day of demand away from diesel in the transportation sector by 2030. At a conversion rate of 5.8 MMBtu per barrel, this would equate to 2.75 Tcf per day by 2030.[41] PIRA's 2030 forecast would raise the domestic natural gas transportation fuel consumption to

[40] Energy Information Administration, *Analysis of the Impacts of the Clean Power Plan*, May 2015, p.15, http://www.eia.gov/analysis/requests/powerplants/cleanplan/pdf/powerplant.pdf (Accessed: June 2015)
[41] PIRA, *An Assessment of the Diesel Fuel Market: Demand, Supply, Trade and Key Drivers*, Commissioned by the Fuels Institute, September 2014, http://fuelsinstitute.org/ResearchArticles/DieselReport_PIRA.pdf (Accessed: June 2015)

9.8% of total domestic natural gas demand by 2030: "*Improvements in efficiency, substitution away from diesel in the non-transportation sector, and growing use of natural gas in the heavy duty vehicle (HDV), railroad, and marine segments are expected to reduce diesel demand in the later years.*"[42] The graph below illustrates the growth of natural gas in heavy duty vehicle use:

Figure 47 – Projections of Natural Gas in Heavy Duty Vehicles



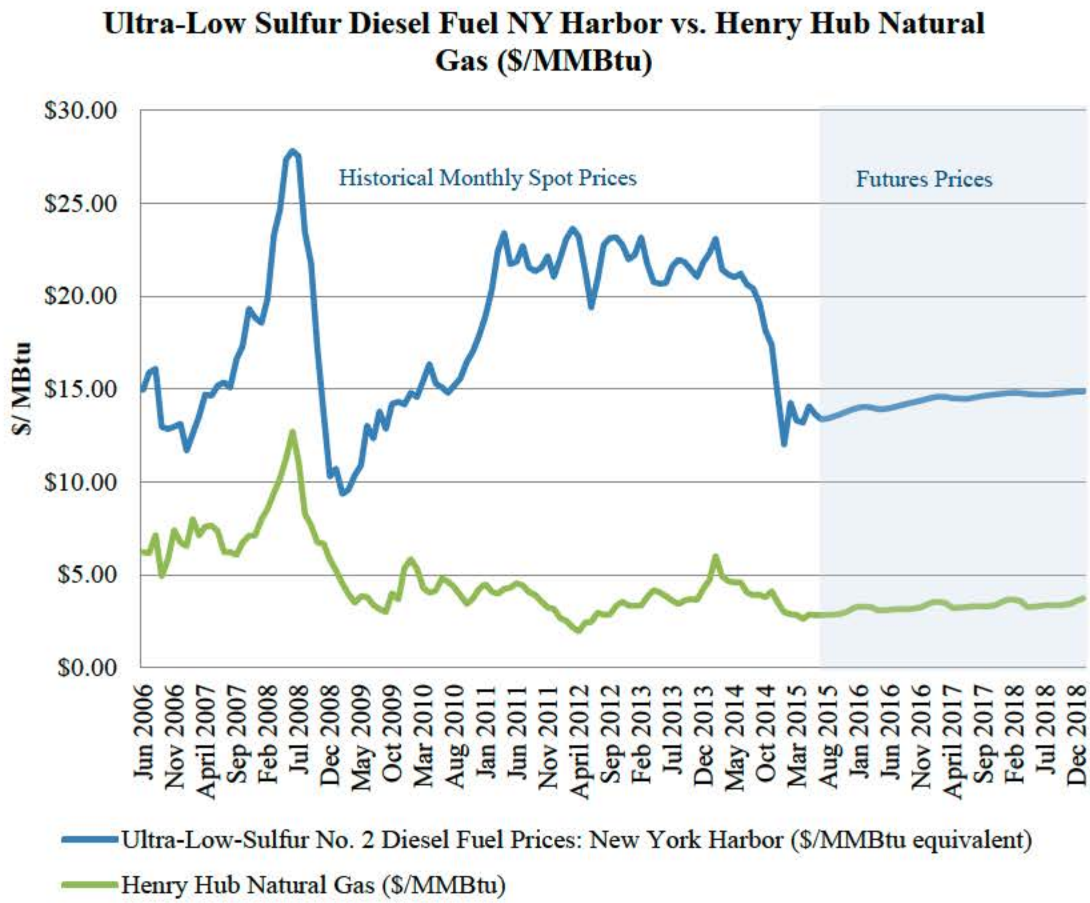
It is very hard to predict the adoption rate of new technologies and the speed of commercialization. So it is not surprising that there should be wide discrepancies forecasting demand for an emerging market. The compelling factors for natural gas conversions from diesel fuel are the fuel cost differential and EPA regulations against emissions. A large price differential between natural gas and refined oil products in combination with environmental regulation could shift demand to natural gas in the marine, road, and rail transportation sectors.

There is a greater financial incentive to switch from ultra low sulfur diesel oil to natural gas, when the price differential between natural gas and ultra low sulfur diesel fuel oil is large. Figure 48 below shows that the price relationship has shrunk from the wide price differential from 2012 to early 2014. But company announcements seem to indicate the recent decline in the

[42] Ibid, p 7.

ultra low sulfur diesel oil price relative to natural gas price has not stopped some users from shifting to natural gas engines.

Figure 48 – Historical and Forward Prices for Ultra Low Sulfur Diesel and Natural Gas



The above graph is the historical monthly Henry Hub Natural Gas for June 2006 through June 2015 (source: EIA) and Ultra Low Sulfur Diesel NY Harbor for June 2006 through June 2015 (source: Federal Reserve Economic Data). The futures prices are CME futures settlement prices for both commodities as of June 19, 2015.

In the marine sector, in 2010 EPA adopted pollution emission standards for ships operating in Energy Control Areas of U.S. waters that extend up to 200 miles off-shore the U.S. coast. Tier 2 standards began in 2011 and more stringent Tier 3 standards begin in 2016 for reduction of emissions in "Category 3" engines, which are large propulsion engines on ships. Ships can meet 2016 Tier 3 targets by 1) burning low sulfur diesel fuel 2) installing scrubbers or 3) switching to an alternative low emissions fuel such as natural gas.

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EIA forecasts the implementation of the new regulation would be addressed by companies installing scrubbers, and for an interim period, demand would be met with distillate fuel:

Figure 49 – EIA's Estimate for How the Marine Sector Will Respond to Environmental Regulation[43]

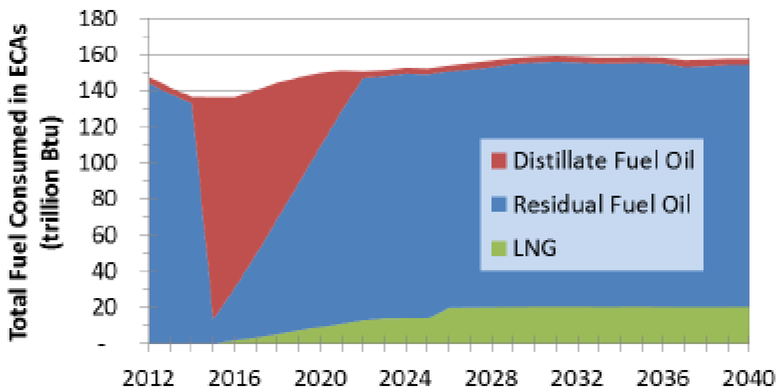


Figure ES- 2. Sample Projections of Fuel Consumed Within North American and U.S. Caribbean ECAs by NEMS Fuel Type

Anecdotally however, it seems the regulation has helped support a number of LNG applications in coastal and international waterways. (In contrast there has been little development on interior waterways.) Most of these projects began two to four years ago and there is considerable lead to receive the necessary permits and authorizations and then to construct the infrastructure:

- TOTE Shipholdings Inc. – TOTE has ordered two Marlin-class vessels with dual fuel engines that can run on natural gas and diesel when needed. The first ship has been launched by General Dynamics NASSCO in San Diego for operation by the company's subsidiary Sea Star Line in its U.S. mainland to Puerto Rico route (April 2015).

- Société de Traversiers du Quebec – The provincial ferry company is receiving its first LNG ferry, a 436 foot vessel with capacity for 800 passengers and 180 vehicles. It has four Wärtsilä 34DF dual fuel engines. In addition to this vessel, the ferry company has ordered construction of two smaller 302-foot vessels, which are also dual fuel (April 2015).

[43] Energy Information Administration, *Marine Fuel Choice for Ocean-Going Vessels Within Emissions Controls Areas*, June 2015, p. ix, http://www.eia.gov/analysis/studies/transportation/marinefuel/pdf/marine_fuel.pdf, (Accessed: June 2015)

- Washington State Ferries – Washington State Ferries operates 22 ferries and has proposed converting six Issaquah class ferries to LNG. Fuel savings over the life of the vessels are estimated to be $195 million. The agency is awaiting a Letter of Recommendation from the U.S. Coast Guard and after that will seek legislative approval and funding (March 2015).

- Harvey Gulf International Marine – The shipping company has constructed the first U.S. flag LNG ship. The vessel is 310 feet long and is powered by three Wärtsilä 6L334DF duel fuel gensets. The company is currently constructing LNG-vessel fueling in Port Fourchon, LA. The facility will consist of two sites each having 270,000 gallons of LNG storage capacity (February 2015).

- BC Ferries – BC Ferries has awarded a construction contract for three LNG ferries to Remontown Shipbuilding S.A. and has negotiated LNG supply from the local gas distribution company, FortisBC. The first ship is due to be delivered August 2016 and the second by October 2016 (January 2015).

- Staten Island Ferry – New York's Staten Island Ferry is moving forward with a pilot project to convert one ship to LNG propulsion. The New York City Department of Transportation issued one RFP for converting a 499-ton ferry to LNG and another RFP for the LNG storage and bunkering infrastructure needed to fuel the ferry (November 2014).

- Waller Marine and Tenaska NG Fuels - Tenaska NG Fuels, LLC and Waller Marine, Inc. are partnering to develop a natural gas liquefaction and fueling facility in the New Orleans- Baton Rouge Mississippi River corridor with access to the Gulf of Mexico. The facility will provide LNG and CNG for marine, transportation, and exploration and production companies (November 2014).

In the road transportation sector, in 2011 EPA and the National Highway Traffic Safety Administration under the direction of the Department of Transportation developed regulation to reduce greenhouse gas emissions from, and increase fuel efficiency use in, heavy duty trucks[44] for model years 2014-2018 ("Heavy Duty National Program"). It applies to all trucks weighing over 8500 pounds. Emissions are expected to drop 17% for diesel trucks and 12% for gasoline trucks by 2018. One way to comply is to use more fuel-efficient diesel engines. Another is to substitute a cleaner-burning fuel like natural gas in the form of LNG which is used in heavy duty trucks and compressed natural gas (CNG) for light duty trucks.

[44] Classes 2B through 8.

There are some challenges for natural gas fired transporters to overcome. First, the cost of the natural gas-fired engine is larger. Even with the lower cost of fuel there is reportedly a 4-year pay-back period.[45] Second, there is a limited amount of gas-fueling infrastructure. Yet despite these challenges, several companies have made investments in LNG and CNG fueling infrastructure.

There are three LNG infrastructure models emerging to serve heavy duty truck fleets. The first is a "return to base" model where trucks return to a single re-fueling point that is a centrally located liquefaction facility. In Colorado, Noble Energy built a 100,000 gallon/day LNG facility in Weld County, CO in 2014 to fuel its drilling rigs and heavy duty trucks. In 2012, Noble also invested in a CNG fueling facility to fuel its thirty three CNG trucks. It also committed $5 million to the Weld County schools to help with CNG busses and construction of a CNG refueling station.

A second model is to develop regional infrastructure to support regional trucking. An example of this is the network that United Parcel Service (UPS) is building. The company plans to have thirteen LNG re-fueling stations operational by 2014 to support truck delivery in Florida, Illinois, Indiana, Mississippi, Missouri, Ohio, Pennsylvania and Texas for 300 heavy duty trucks and 700 gas tractors.

A third model is where a retailer builds out a network to support customers and provides fleet fuel supply. Clean Energy operates twenty four LNG-only, sixteen LNG and CNG combined, and one hundred and seventy CNG-only public fueling stations. In addition to the public fueling stations, they currently have another ninety one LNG and CNG truck accessible stations and with another sixty seven planned. Along with operating fueling facilities, Clean Energy also supplies a number of airport bus fleets (at thirty eight airports), shuttle fleets (Super Shuttle), and waste hauling fleets.

Shell Oil LNG has built a triangle of LNG fueling stations at several TravelCenters of America in Texas and Louisiana at San Antonio TX, Dallas TX, Baytown TX, and Lafayette LA. Shell also operates in two regional corridors. It has two fueling stations in California, one in Santa Nella CA and one in Ontario CA. It also opened two LNG fueling stations in 2013 in Alberta, one in Calgary and one in Edmonton. Gulf Oil has installed LNG fueling in Massachusetts and Rhode Island and converted forty four of its trucks to LNG fueling. Gulf is also developing a "return to base" model, constructing a 100,000 gallon merchant LNG facility in Great Bend PA (in the Marcellus shale region) to serve drilling and transport companies operating locally.

[45] Bob Tita, Wall Street Journal, *Slow Going for Natural-Gas Powered Trucks*, August 25, 2014, http://www.wsj.com/articles/natural-gas-trucks-struggle-to-gain-traction-1408995745 (Accessed: June 2015)

In Canada, Ferus Natural Gas owns an LNG terminal in Grand Prairie to sell LNG fuel to drilling rigs, pressure pumping equipment and heavy duty tricks working in the Deep Basin oilfields. It has a five year supply deal with Encana, the prior 50% owner of the facility. Ferus is also partnering with ENN Canada Corp to build gas liquefaction plants in Edmonton and Vancouver. ENN Canada currently operates three LNG refuelling stations, two in British Columbia and one in Ontario along major transportation routes.

Compressed natural gas (CNG) has been making in-roads with smaller duty trucks, taxi fleets, and bus lines. In February 2015, Saddle Creek Logistics Services announced that over three years it has reached the "34-million-mile mark" with its *Power to the People* program. It started with forty CNG fueled tricks in 2012 and the fleet now has one hundred and seventy tractors. There are plans to replace the entire fleet of diesel trucks (four hundred and twenty in total) over the next few years. Its delivery territory extends to the Southwest and Southeast states. Saddle Creek markets its clean fuel transportation services to retailers like Lowes and Proctor & Gamble. Trucks fuel at its Lakeland FL campus.

Since the mid-1990s, Questar Fueling (subsidiary of Questar Corporation) has been operating over seven hundred of its own natural gas vehicles. Today it operates twenty eight public natural gas fueling stations and has assisted the state of Wyoming with developing another five semi-public stations. These have been developed into an interstate natural gas fueling corridor.

In October 2013, AMP Americas signed a deal with Dairy Farmers of America and Select Milk Producers, to convert their fleets to CNG. AMP CNG manages a fleet of 42 milk transport trucked fueled with CNG. AMP CNG currently owns and operates 20 CNG stations around the country, with plans for 35 by the end of 2015 and ultimately more than 100 in Texas, the Midwest and the Southeast.

In the rail sector, EPA finalized regulation to reduce diesel locomotives' emissions by as much as 90% for new manufactured engines built in 2015 and later. EPA standards also apply for existing locomotives when they are re-manufactured. As a result several railroads are looking at using natural gas as a transportation fuel.

According to EIA, railroad diesel consumption represents 7% of total U.S. diesel retail sales.[46] Although several railroads are testing LNG locomotives, none have gone into service yet. There are a couple of operational hurdles to overcome. First, there are no available engine kits to

[46] Energy information Administration, *Liquefied Natural Gas Shows Potential As a Freight Locomotive Fuel*, April 14, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=15831 (Accessed: June 2015).

support dual fuel operations (ex: diesel and natural gas). Second, the tender cars carrying LNG still need to be developed. And most importantly there is no fueling infrastructure.

Unlike a trucking return to base model or a medium-distance corridor or triangle, trains travel a long distance for each trip. So trains use 'tenders' to carry their fuel with them. EMD (subsidiary of Caterpillar) has developed three technologies for burning LNG in locomotive diesel engines: Spark Ignited (100% LNG), Dynamic Gas Blending™ (dual-fuel, up to 60% LNG), and High Pressure Direct Injection (up to 95% LNG). In 2014 BNSF took delivery of an LNG locomotive from EMD and another from GE. These have been tested in the southwest and were transferred to a northern location to test in different ambient temperatures. This is still a pilot project and the long-term commercial feasibility is unknown.

In March 2015, Union Pacific Railroad filed for a permit to haul LNG with the Federal Railroad Administration, in response to a request for LNG transportation from an existing customer. It is the first U.S. railroad to request to haul LNG. Canadian National Railroad tested two LNG engines in 2013, on a short haul route between Edmonton and Fort McMurray. These were retrofitted diesel engines that ran on 90% natural gas. Then, in March 2015, Canadian National Railroad received four prototype LNG tenders from Westport Innovations to use when testing LNG locomotives. But in a recent earnings release, Westport announced it would pause further investment in LNG tenders until it is clear there is a more clear demand. Westport has had consolidated net losses from several years and announced cutting back expenses in spring 2015. In November 2013, CSX Corporation and GE Transportation announced plans to field test LNG technology in its locomotives in 2014.The CSX engines would use natural gas retrofit kits that GE had designed.

Export Demand

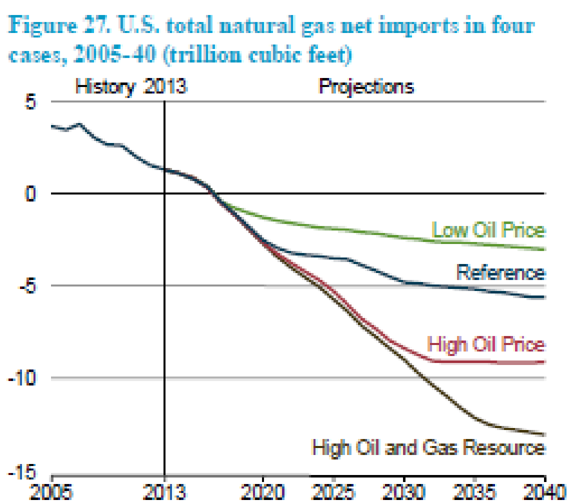
Similar to demand for electric generation and transportation fuel, natural gas export demand is subject to many variables. Export and construction approvals must be obtained, export liquefaction capacity must be built, new export markets must be sought, and U.S. LNG must be competitively priced. There are other countries expanding their supply capacity, competing to obtain market share. And the pricing differential must be sustainable to make the significant investment in LNG export capacity attractive.

Based upon the analysis conducted, Aether anticipates the current LNG expansion cycle has more substance than the prior "LNG import" cycle in 2008-2009 that never materialized. If the capacity is built and purchased, then U.S. LNG exports are very likely. And there appears to be significant momentum behind the commercialization of U.S. LNG exports. This goes beyond the pace of FERC and DOE approvals of projects which has taken place. U.S. projects have executed long-term contracts and benefit from an infrastructure cost advantage compared to projects in other LNG exporting countries.

A. U.S. Natural Gas Export Forecasts

In all of the EIA AEO cases, the U.S. becomes a net exporter of natural gas by 2017. The Reference Case shows exports growing from 2 Tcf to 6 Tcf per year. The two High Oil Price and High Oil and Gas Resource cases show much more significant exports.

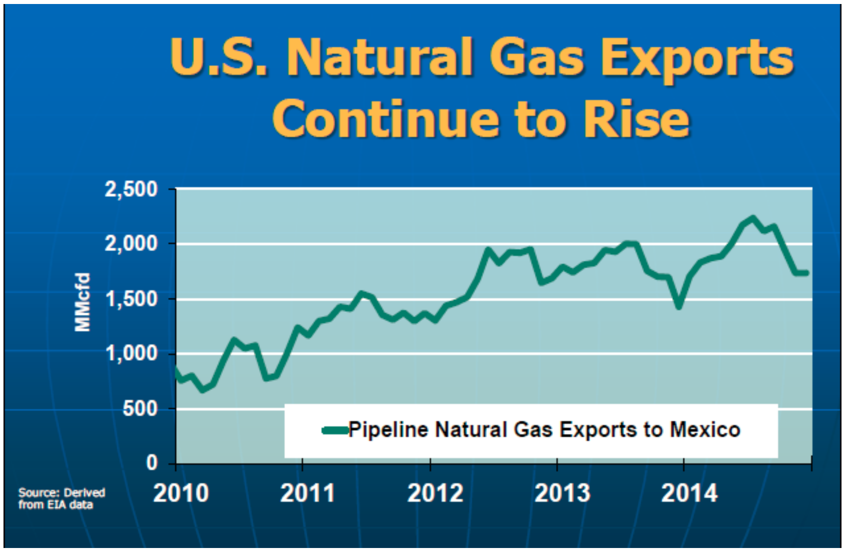
Figure 50 – Net Natural Gas Imports in EIA's 4 Cases[47]



Exports to Mexico are often overlooked because exports occur through existing pipeline infrastructure. Mexican purchases of U.S. natural gas have been slowly climbing in recent years. FERC staff summarized the recent trend in exported natural gas to Mexico in the Winter 2014-2015 Energy Market assessment:

[47] U.S. Energy Information Administration, *Annual Energy Outlook 2015 With Projections to 2040*, DOE/EIA-0383(2015) April 2015, 21.

Figure 51 – FERC: Growing U.S. Natural Gas Exports to Mexico[48]



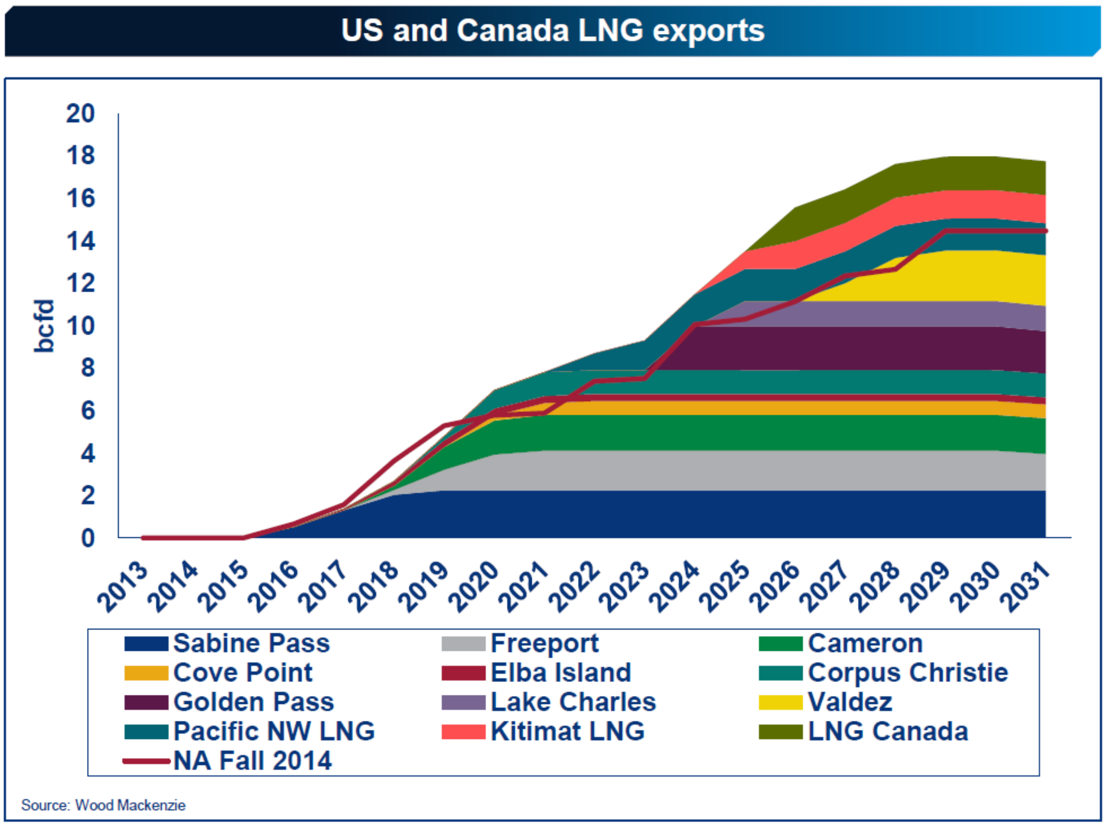
In its AEO2015 Reference case, EIA is projecting continued growth in exports to Mexico from 0.7 Tcf per year in 2013 to 3.0 Tcf in 2040 in the Reference case. In its High Oil and Gas Resources case, the 2040 estimate is 4.7 Tcf and the 2040 estimate is 2.2 Tcf in the High Oil Price case.

In its AEO2015 Reference case, EIA forecasted net LNG exports of natural gas of 2.08 Tcf/year (5.7 Bcf/day) by 2020 and 3.29 Tcf/year (9 Bcf/day) by 2030. The forecast remains constant from 2030 to 2040. That would equate to 8.0% of total domestic gas demand by 2020, and 11.7% by 2030 and 11.1% by 2040. In contrast, the Brookings Institute wrote "We believe that the U.S. LNG projects that are currently under construction totaling close to 10 Bcf/d in capacity, will make it to the market by 2020".[49] 10 Bcf/day of net LNG exports would equate to 14% of domestic demand. Black & Veatch estimated between 10-14 Bcf/day of exports by 2020 based upon the number of FERC and DOE approvals and the announced capacity of the approved facilities,[50] a range of 14% to 19.5% of domestic demand And, Wood Mackenzie forecasted as much as 6-8 Bcf/day U.S. LNG exports (8.4% to 11.2% of domestic demand) by 2020 and 16-18 Bcf/day Canadian and U. S. LNG exports by 2031.[51] The U.S. has historically been a net

[48] Federal Energy Regulatory Commission, *2014 State of the Markets, Item No. A-3, March 19, 2015*, FERC Staff presentation to FERC Commissioners, October 2014
[49] Brookings Institute, Natural Gas Issue Brief #4: *An Assessment of U.S. Natural Gas Exports*, Brookings Energy Security and Climate Initiative Natural Gas Task Force, July 2015, P 14.
[50] Black & Veatch, *2014 Strategic Directions: U.S. Natural Gas Industry*, 2014, 36.
[51] David Pruner, Senior Vice President, Wood Mackenzie, *North American Natural Gas Market and the Shale Revolution*, May 19, 2014.

importer of LNG, so the forecasted range in net LNG exports would represent sizeable export demand relative to domestic demand.

Figure 52 – Wood Mackenzie LNG Exports[52]



The key drivers to liquefied natural gas (LNG) exports are the export infrastructure, price competitiveness of U.S. LNG compared to international prices, and the structure of supply and demand in non-U.S. markets. These key drivers are explored in the following sections.

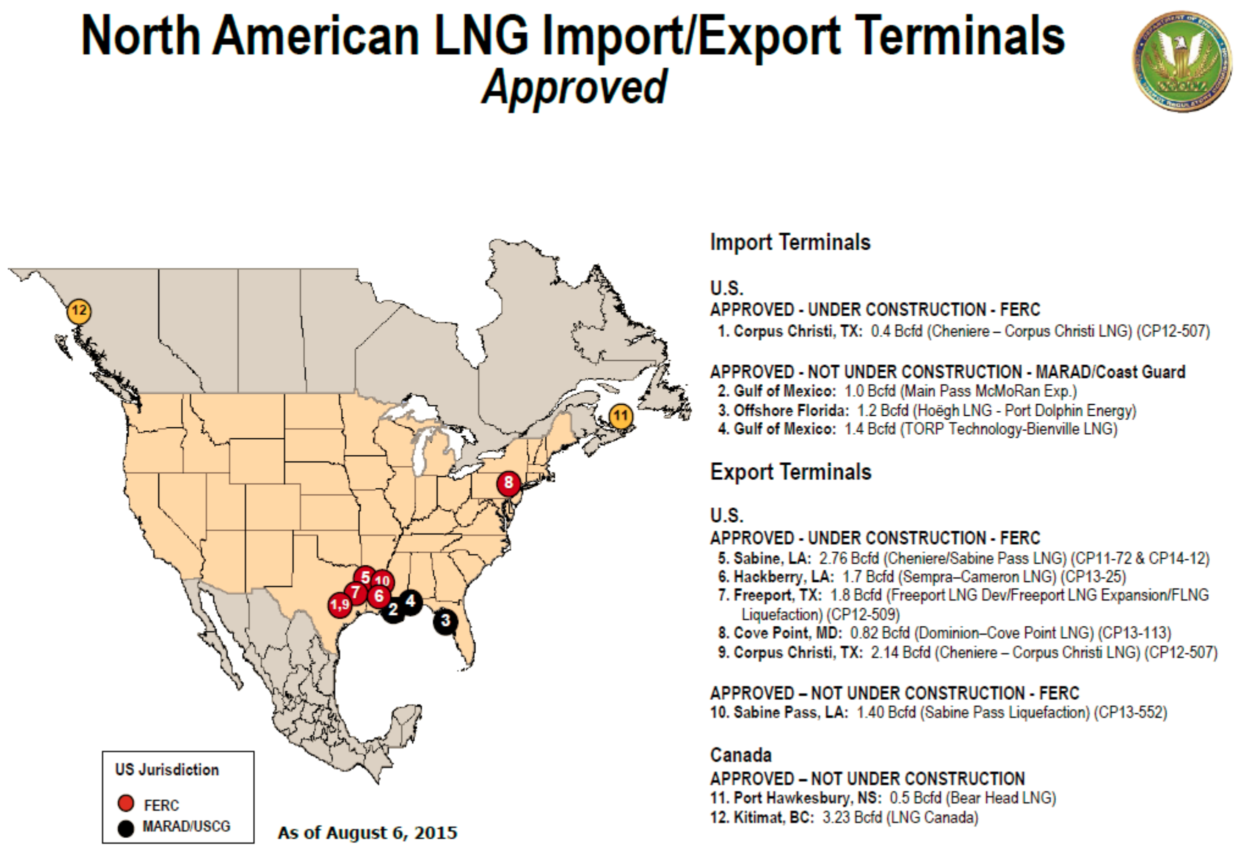
B. Export Approvals and Infrastructure

In recent years there have been numerous projects announced for developing export capabilities to export Canadian and U.S. natural gas. The U.S. Department of Energy (DOE) and Federal Energy Regulatory Authority (FERC) have approved export permits for several U.S. LNG

[52] David Pruner, Senior Vice President, Wood Mackenzie, *North American Natural Gas Market and the Shale Revolution*, May 19, 2014

facilities. The map below summarizes the approved projects in North America. In the U.S., there are already 8.4 Bcf/day of approved LNG export terminals under construction:

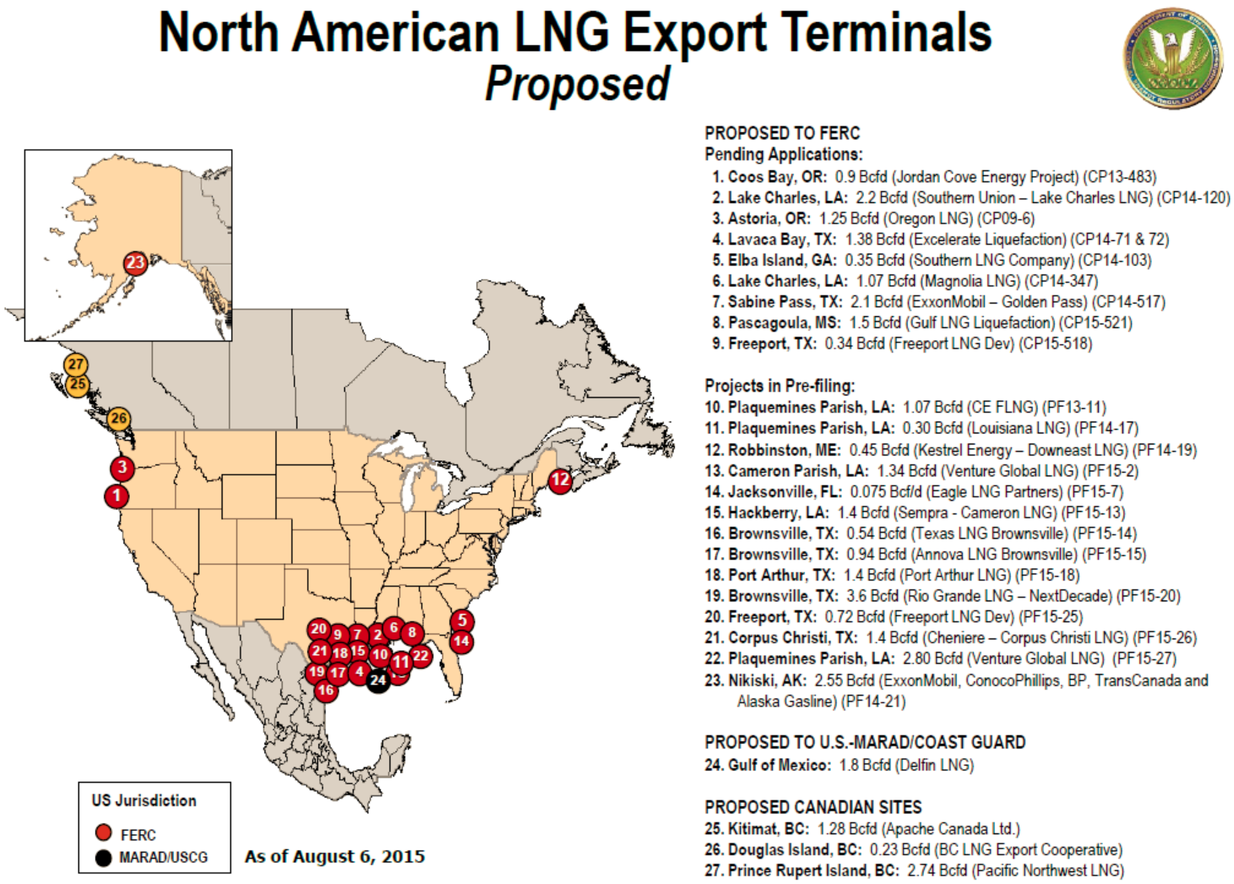
Figure 53 – Approved North American LNG Export Terminals[53]



Further, there is over 29 Bcf/day of export terminals proposed to FERC, awaiting approvals. It is unlikely that these terminals will all be approved and constructed, but while U.S. gas prices are low relative to international gas prices, these terminals are likely to continue to draw investor interest.

[53] Department of Energy, Office of Energy Projects, *North American LNG Import/Export Terminals Approved*, August 6, 2015, http://www ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf (Accessed: August 2015)

Figure 54 – Proposed North American Export Terminals (DOE)[54]



The terminals are not being built as merchant facilities to sell capacity into a spot market, but instead are contracting capacity under long-term contracts to large, credit worthy global energy companies. This is facilitating financing of the facilities, greatly increasing the likelihood of the approved terminals being built. And once built and contracted, then the facilities will be used whenever market spreads are above the variable costs of shipping LNG from U.S. ports.

As of May 27, 2015, DOE has received applications for 46.51 Bcf/day LNG export capacity. The majority of the approvals have been for export to non-Free Trade Agreement ("FTA") countries[55] (the major LNG importing areas such as Japan, China, Europe and India are non-FTA

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[54] Department of Energy, Office of Energy Projects, *North American LNG Import/Export Terminals Approved*, August 6, 2015, http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf (Accessed: August 2015)

[55] Department of Energy, *Long-Term Applications Received by DOE/EE to Export Domestically Produced LNG from the Lower-48 States*, May 13, 2015, Note, Section 3 of the Natural Gas Act (NGA) (15 U.S.C. § 717b) prohibits the import or export of natural gas, including liquefied natural gas (LNG) from or to a foreign country

countries). Because the larger LNG importers are non-FTA countries it is non-FTA country approvals that be monitored closely. Developers will not likely construct capacity without the non-FTA approvals.

Many of the proposed U.S. LNG export facilities are already import facilities, so they are "brownfield" development projects as opposed to new "greenfield" construction projects. The projects that are currently LNG import terminals already have a physical site, pipeline infrastructure and ship berths. This means the addition of liquefaction is an incremental capital investment and the facility has already gone through one environmental impact study as an import facility. As a result, the time until commercial operations commence is reduced with a brownfield facility.

In Canada, according to section 118 of the National Energy Board Act ("NEB Act"), the NEB must assess whether the proposed gas for export does not exceed the surplus remaining after taking into consideration foreseeable requirements for use in Canada. Fisheries and Oceans Canada reviews the environmental impact of an export terminal and Transport Canada reviews the proposal to transport LNG in Canadian waters. An export terminal must also receive provincial government approval to proceed. The National Energy Board (NEB) has approved thirteen export terminal applications.

Figure 55 – NEB-Approved Export Authorizations [56]

Company	Term Length	Project Sponsors and Capacity (Bcf/day estimates)
KM LNG Operating General Partnership (BC)	20 years	Apache Canada and Chevron Canada 1.4 Bcf/day
LNG Canada Development Inc. (BC)	25 years	Shell Canada, KOGAS, Mitsubishi and Petrochina 2.0-3.2 Bcf/day
Pacific Northwest LNG Ltd. (BC)	25 years	Petronas and Japex 2.0 Bcf/day

without prior approval from the Department of Energy (DOE). Section 3(c) of the NGA was amended by section 201 of the Energy Policy Act of 1992 (Pub. L. 102-486) to require that applications to authorize (a) the import and export of natural gas, including LNG, from and to a nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas are deemed to be within the public interest. Applications to non-FTA countries require additional review and approval.
http://energy.gov/sites/prod/files/2015/05/f22/Summary%20of%20LNG%20Export%20Applications.pdf, (accessed June, 2015)

[56] National Energy Board, LNG Export and Import License Applications, https://www.neb-one.gc.ca/pplctnflng/mjrpp/lngxprtlcnc/index-eng.html (Accessed June 2015).

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Company	Term Length	Project Sponsors and Capacity (Bcf/day estimates)
WCC LNG Ltd. (BC)	25 years	Imperial Oil and ExxonMobil Canada 4.0 Bcf/day
Prince Rupert LNG Exports Limited (BC)	25 years	BG Group Up to 3.0 Bcf/day (3 trains)
Woodfibre LNG Export Pte. Ltd. (BC)	25 years	Pacific Oil & Gas Limited .3 Bcf/day
Jordan Cove LNG L.P. (OR)	25 years	Veresen Inc. .8 Bcf/day potential to expand to 1.1 Bcf/day
Triton LNG Limited Partnership (BC)	25 years	AltaGas Ltd. and Idemitsu Canada .27 Bcf/day million
Aurora Liquefied Natural Gas Ltd. (BC)	25 years	CNOOC (through Nexen), Inpex Corp and JGC Corp 1.56 Bcf /day, going to 3.11 Bcf/day
Oregon LNG Marketing Company LLC (OR)	25 years	80% Leucadia National Corp; 1.3 Bcf/day
Canada Stewart Energy Group Ltd. (BC)	25 years	Privately held, .63 Bcf/day floating LNG initially, followed by 3.18 Bcf/day land-based
WesPac Midstream-Vancouver LLC (BC)	25 years	WesPac Midstream (majority held by Highstar Capital LP), .4 Bcf/day
Woodside Energy Holdings Pty Ltd.	25 years	Woodside Energy Ltd, 2.5 Bcf/day

Note- Applications to NEB are stated in million tons per annum. Aether inserted volume in Bcf/day, using company announcements or CAPP[57] descriptions for the following: KM LNG, BC LNG, LNG Canada Development, Pacific Northwest LNG, WCC LNG, Prince Rupert LNG, Woodfibre LNG, Triton LNG, Oregon LNG and WesPac. For the other facilities, Aether used the DOE's conversion rate of 1 Bcf/day = 7.82 million tons per annum.[58]

None of the LNG export terminal projects has yet advanced to a final investment decision state ("FID"). Most of the Canadian facilities are greenfield developments, with longer lead time, more permitting, and greater up front capital investment than most of the U.S. facilities. Aside from the geographical advantage to Asian markets, the Canadian projects lack much of the permitting and brownfield construction advantages of the U.S. projects.

[57] Canadian Association of Petroleum Producers (CAPP), *Canada's Natural Gas and Oil Resources on a Global Stage*, Vancouver Board of Trade, November 5, 2013, p 15.
http://www.capp.ca/getdoc.aspx?dt=ntv&docID=234106, Accessed July 2014.

[58] There is no single conversion rate for million tons per annum to Bcf/day, so Aether applied the DOE conversion rate to million tons per annum announcements for Canadian export facilities.

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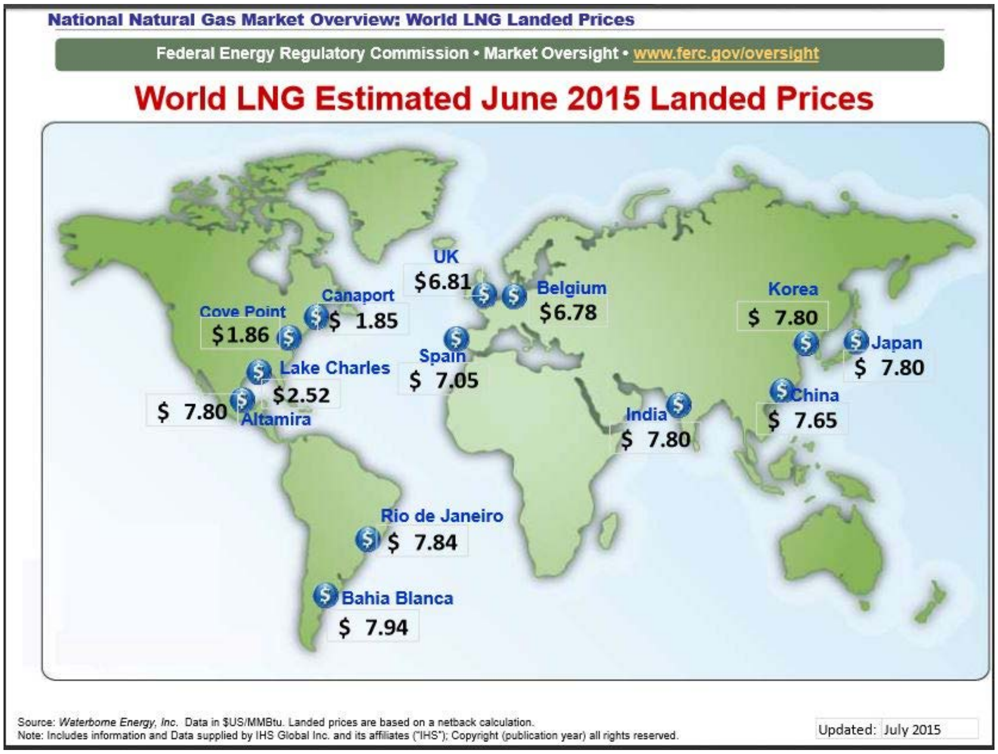
C. U.S. LNG Competitiveness

A commodity flow analysis identifies premium and discount markets to determine the logical flow of commodity movements. For example, the map below provides a sense for how North American natural gas prices compare to global natural gas prices. Despite the decline in global oil prices, the map below shows the large discount between North American gas prices and global natural gas prices:

Figure 56 – World LNG Prices (FERC) [59]



According to a 2013 report "U.S. Liquefied Natural Gas Exports: A Primer on the Process and the Debate",[60] Cheniere Energy estimated a cost of $3.07/Mcf, for liquefaction, and a cost of $1.02 per Mcf to ship LNG to Europe and $3.07/Mcf to ship it to Asia. Every operator's economics will be different, but it appears the current spot market price differential between U.S.

[59] Federal Energy Regulatory Commission, *Market Oversight*. Source: Waterborne Energy, Inc., June 2015, http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf (accessed: June 2015)

[60] Gwynne Taraska, Center For American Progress, *U.S. Liquefied Natural Gas Exports: A Primer on the Process and the Debate*, November 5, 2013, http://www.americanprogress.org/issues/green/report/2013/11/05/78610/u-s-liquefied-natural-gas-exports/ (accessed: December 2013)

Gulf Coast and Europe meets the $4.09 Cheniere cost hurdle but the current market price differential between U.S. Gulf Coast and Asia is less than the Cheniere cost hurdle of $6.14. But the LNG global prices in the map above represent spot market pricing. There have been several long-term U.S. export contracts announced with a variety of international companies engaged in LNG trade or consumption:

- Cameron LNG – GDF SUEZ S.A., Mitsubishi Corporation, and Mitsui & Co., Ltd. signed 20-year tolling capacity and joint-venture agreements to commit the full nameplate capacity of the three-train, 13.5- million-tonnes-per-annum (Mtpa) facility that will provide an export capability of 12 Mtpa of LNG, or approximately 1.7 billion cubic feet per day (Bcf/day), and the full regasification capacity of 1.5 Bcf/day. Each tolling agreement is for 4 Mtpa.

- Corpus Christi – Cheniere has entered into nine fixed price 20-year contracts for approximately 8.4 mtpa. The pricing terms are $3.50 /MMBtu plus 115% of Henry Hub index price. The contracts are with the following market participants: Endesa Generacion S.A., Iberdrola S.A. Gas Natural Fenosa SL, Woodside Energy Trading Singapore Pte Ltd, PT Pertamina (Persero), Electricité de France, and EDP Energias de Portugal S.A.

- Dominion Cove Point – Dominion has fully subscribed the marketed capacity of the project with 20-year service agreements with ST Cove Point, LLC, a joint venture of Sumitomo Corporation, a Japanese corporation that is one of the world's leading trading companies, and Tokyo Gas Co., Ltd., a Japanese corporation that is the largest natural gas utility in Japan; and GAIL Global (USA) LNG LLC, a wholly owned indirect U.S. subsidiary of GAIL (India) Limited, one of the largest natural gas processing and distributing companies in India.

- Freeport LNG – Freeport LNG Expansion LP signed an agreement allowing a BP PLC unit to export 4.4 million metric tons a year of liquefied natural gas out of its terminal in Freeport, Texas in 2013.

- Sabine Pass – Cheniere has entered into four fixed price twenty-year agreements for a total of 16 mtpa (~ 803 Bcf/year). The buyers include BG Gulf Coast LNG LLC, Gas Natural Aprovisionamientos (Gas Natural Fenosa), Korea Gas Corporation (KOGAS), Gail (India) Limited, Total, and Centric plc.

In addition to permitting and licensing challenges, project feasibility is heavily influenced by global crude oil prices. Historically, more than 75% of Asian LNG transactions have been based upon oil price index.[61] It is not clear if this trend will continue, or if global LNG pricing will tie more closely to natural gas price benchmarks in North America. Asian landed prices dropped 30% in 2014, following the decline in global crude oil prices.[62] However, Cheniere's pricing terms for sales from its Sabine Pass terminal is indicative of a trend for U.S. facilities to price LNG off of a North American index. Additionally, U.S. facilities' long-term contracting may help insulate these projects from the recent price declines.

D. Global LNG Market

As North American gas becomes increasingly linked to international markets, supply and demand factors elsewhere in the world will impact natural gas prices. Therefore, determining where long-term U.S. natural gas prices may go requires some insight to global gas market drivers.

Ernst & Young (E&Y) published a report in April 2014 that examined the risk factors of falling world crude oil prices on delivered LNG projects.[63] They concluded that with a $5.00 MMBtu domestic gas price, U.S. Gulf Coast LNG to Asia would be attractive compared to oil-linked contracts until oil prices fell to $75 bbl ($60/bbl for west coast exports). In a similar analysis, they determined that at a $5.00 MMBtu domestic price, U.S. Gulf Coast LNG to Europe could compete against oil-based LNG contracts until crude oil prices dropped to $60 bbl. This would suggest the U.S. LNG exports would continue given EIA's projected natural gas and crude oil price differential.

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[61] Giorgio Bresciani, Dieuwert Inia, and Peter Lambert, McKinsey, *Capturing Value in Global Gas McKinsey on Oil and Gas- Prepare Now for an Uncertain Future*, McKinsey on Oil and Gas, April 2014, 6.
[62] International Energy Agency, *Gas Medium-Term Market Report 2015: Market Analysis and Forecasts to 2020*, 2015, 15.
[63] Ernst & Young, *Competing for LNG Demand: The Pricing Structure Debate*, 2014, 5.

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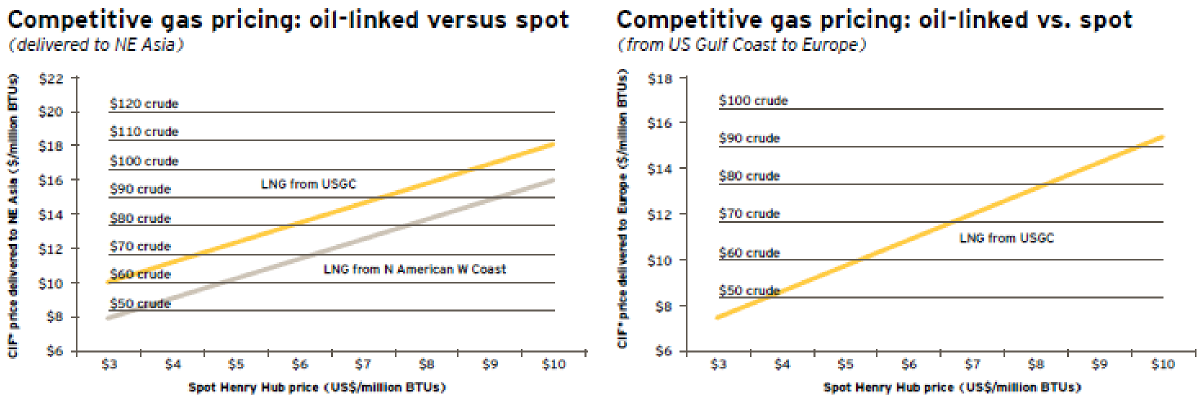
Figure 57 – E&Y Analysis of Crude Price on US LNG Exports

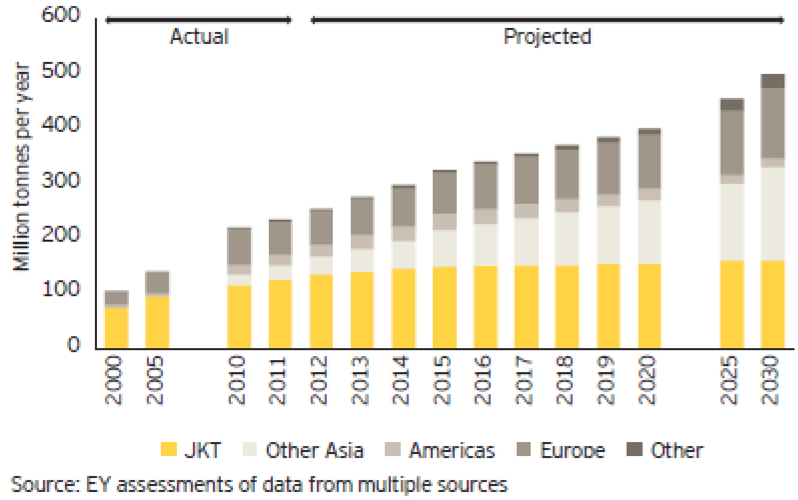


On a global basis, there is more demand today than supply, according to a BG LNG Outlook 2014-2015 report. Asia accounts for 75% of global demand, followed second by Europe. In 2014, Lithuania became the most recent country to import LNG. And five new import terminals were built in Asia (Japan – 1, South Korea – 1, Indonesia –1, and China – 2). All of Japan's nuclear facilities are still off-line so it is importing its maximum capacity of LNG. On the supply side, Papua New Guinea (PNG) began exporting LNG and Australia loaded its first cargo in 2014. In 2015, Australia will be exporting more cargos, and the first cargos from the U.S. may occur by the end of the year.[64]

According to a 2014 E&Y report, global LNG demand experienced strong growth of 7.6% per annum during that period. A large part of the growth began in 2011 when Japan closed down 20% of its nuclear fleet and began importing LNG after the Fukushima nuclear incident. China has been increasing LNG exports at a fast pace in recent years (13.1% year over year growth in 2013 alone). The figure below provides E&Y's forecast for future LNG demand:[65]

[64] BG Group, *LNG Outlook 2014-2015*, "Global trade summary for 2014: The Hiatus Continues", March 14, 2014.
[65] EYGM (a division of Ernst & Young), *Global LNG- Will New Demand and New Supply Mean New Pricing?* 2013.
http://www.ey.com/Publication/vwLUAssets/Global_LNG_New_pricing_ahead/$FILE/Global_LNG_New_pricing_ahead_DW0240.pdf, accessed July 2014.

Figure 58 – E&Y Forecast of LNG Imports



On a global scale, there are over 30 countries currently with LNG liquefaction capability or that have announced plans to add liquefaction, and the announced projects have the potential to take total demand from 600 million tons per annum (mtpa) in 2011 to 800 mtpa by 2020. Japan, Korea and Taiwan ("JKT" in the graph above) have limited domestic energy sources, and have historically been premium-priced LNG markets. In Asia, the long-term demand uncertainties are Japan and China. Today, many of Japan's nuclear plants are still off-line, but when they return, LNG demand is likely to drop. IHS forecasted Japanese LNG imports could decline from 88 MMt in 2013 to 80 MMt by 2020.[66]

The International Energy Agency ("IEA") forecasts global gas demand will slow in the years up to 2020 to 2% per year from the 2.3% growth rate of the prior decade.[67] Similar to E&Y, IEA predicts the growth areas for LNG will continue to be Asia, primarily China, and to a lesser degree South America and Europe. Because the LNG to coal price spread has narrowed, IEA forecasts China demand growing 10% per annum during the period to 2020.[68] There are a number of factors that could influence Chinese LNG imports. Key questions are: What is the continued rate of economic growth in China? How truly committed is China to shifting from coal to cleaner fuels? What Chinese shale gas formations can be exploited and at what cost can China's shale gas be produced? There have been very little geological shale studies to date, so

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[66] IHS, *Japan: Sluggish Nuclear Start-Up Leads to Continued High LNG Demand*, LNG Value Chain & Markets Service, August 2014, 4.
[67] International Energy Agency, *Gas Medium-Term Market Report 2015: Market Analysis and Forecasts to 2020*, 2015, 12.
[68] Ibid.

the Chinese shale gas availability and cost are not well known. Signs today are that LNG will continue to be of key importance to China, but this will bear watching.

According to data from the European Commission Eurostat, Europe imports 65% of its natural gas, over 69% from Russia and Norway as of 2013. The balance comes from Algeria, Qatar, Nigeria, Egypt and other countries.[69] In terms of future European LNG demand, while forecasts call for continued growth, projected LNG demand growth is slower than in Asia. European LNG demand projections are based in part on Russian exports. On one hand, Europe may be a marginal LNG market for U.S. exports because there is alternative pipeline gas supply coming from Norway and Russia. Additionally Europe has made significant investment in renewable energy and nuclear energy. But, on the other hand, recent conflicts in the Ukraine and Russia's increasing focus on contracting to China may mean greater opportunity for U.S. LNG exports to Europe. Long-term Europe's LNG demand is growing because OECD European production declines of 25% from 2010 to 2020.[70]

In its 2035 Energy Outlook, BP forecasts the following increases in global demand and supply in Figure 59. LNG supply grows by 48 Bcf/day by 2035, with a 7.8% per annum between 2013 and 2020. Australia is forecasted to contribute 16 Bcf/day and the U.S. 14 Bcf/day. BP's estimate of U.S. LNG exports significantly exceeds EIA's Reference Case forecast.

[69] European Commission Eurostat, EU-27 Imports of Natural Gas, http://epp.eurostat.ec.europa.eu/statistics_explained/index.php?title=File:EU-27_imports_of_natural_gas_-_percentage_of_extra-EU_imports_by_country_of_origin,_2012.png&filetimestamp=20130529121346, accessed July 2014.

[70] International Energy Agency, *Gas Medium-Term Market Report 2015: Market Analysis and Forecasts to 2020*, 2015, 60.

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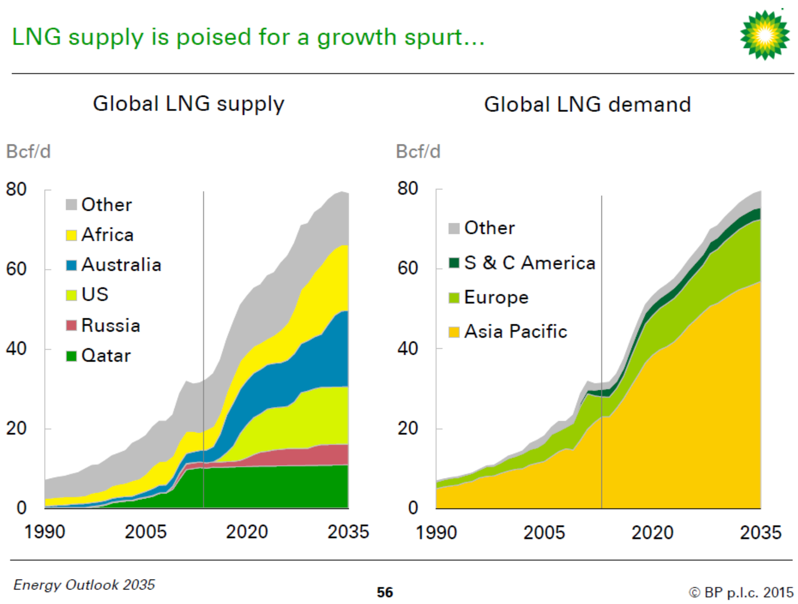
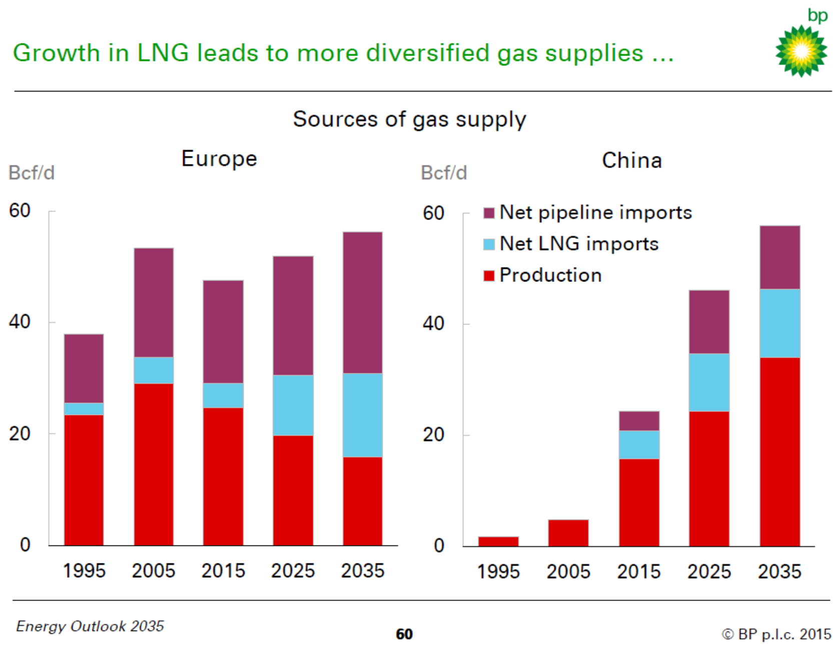
Figure 59 – BP's Projections of Global LNG and Demand by Major Source/Destination[71]



Asian demand retains the largest share of LNG demand, staying above 70% of total demand. In BP's projections, by 2035 Japan is the largest Asian importing country at 13 Bcf/day, followed closely by China at 12 Bcf/day. Europe also remains a significant importer of LNG but at a slower growth rate. The following graph in Figure 60 shows the projected composition of gas supply for Europe and China from 1995 to 2035:

[71] BP Energy, Energy Outlook 2035, presentation, 56, 2015.

Figure 60 – Europe and China Gas Demand by Type



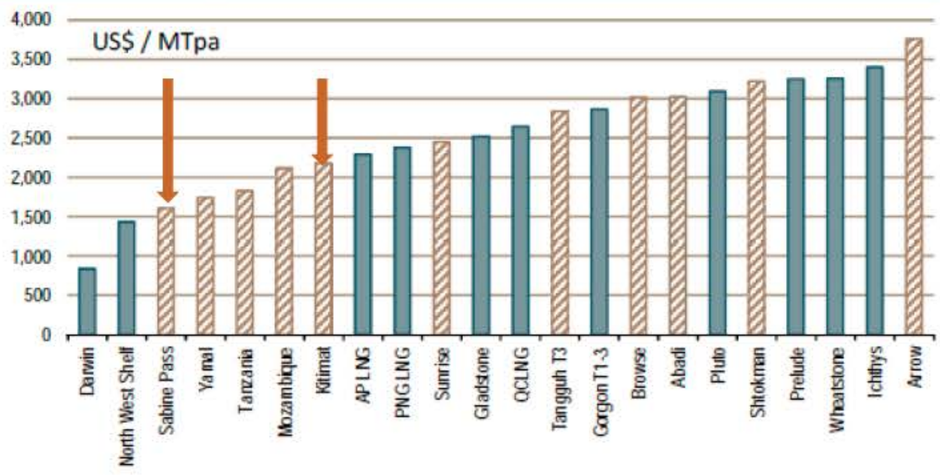
An important consideration is whether the U.S. will be a competitive marginal cost producer. LNG exporting countries historically were Algeria, Egypt, Nigeria, Australia, and Russia. Currently Qatar is the largest LNG exporter, and based upon announced projects, Australia and the U.S. are predicted to will soon catch up and potentially surpass the other producers in output in the upcoming years. Very large LNG export capacity additions in the U.S. and Australia will increase capacity by 40% from now until 2020, with the largest increases in 2016-2017.[72]

In a February 2015 report Credit Suisse wrote that the Australian LNG market might struggle to export all the projected LNG because of constraints and high costs of domestic LNG. Additionally, Australia's LNG facilities are greenfield new construction, whereas many of the U.S. facilities are brownfield facilities. This is supported by a 2012 Credit Suisse analysis, which illustrates the relative cost advantage that the two illustrative North American LNG export facilities have relative to other global projects. The North American examples - Sabine Pass in the U.S. Gulf Coast and Kitimat in British Columbia - are lower on the global LNG cost curve than many of the other proposed LNG projects elsewhere in Asia, Australia and Russia.[73]

[72] Ibid, 13.
[73] Credit Suisse, *Global LNG –Update*, Connection Series, June 7, 2012, 3.

Figure 61 – Credit Suisse Projection of Global LNG Project Costs

Figure 6: **Global LNG cost curve—East Africa and North America well positioned**



Source: Company data, Credit Suisse estimates

Key:

Darwin (Australia)	QCLNG (Australia)
North West Shelf (Australia)	Tangguh T3 (Indonesia)
Sabine Pass (U.S. Gulf Coast)	Gorgon T1 (Australia)
Yamal (Russia)	Browse (Australia)
Tanzania (Tanzania)	Abadi (Indonesia)
Kitimat (British Columbia)	Pluto (Australia)
AP LNG (Australia)	Shtokman (Russia)
PNG LNG (Papua New Guinea)	Prelude (floating LNG ship)
Sunrise (Off-shore Australia/Timor Leste)	Wheatstone (Australia)
Gladstone (Australia)	Ichythis (Australia) Arrow (Australia)

To summarize, the global LNG market has a number of demand and supply uncertainties. On both the demand and supply side, large growth is projected. Supply is more "chunky" in that new capacity is added at one time whereas demand growth occurs over a more gradual time period. There is production uncertainty among a number of the exporting countries, either because of natural gas supply uncertainty or political instability. And the demand projections are uncertain, where demand increases depend upon the rate of economic growth, fuel switching from coal, the competitiveness of renewable and nuclear energy projects, and general geopolitics. That said, U.S. LNG producers appear to be relatively well-positioned to compete in the market by virtue of a supportive regulatory approval process, lower costs to build export capacity, shorter construction time, evidence of long-term contracts, and the lowest cost origin gas.

Part 4 – Portfolio Modeling

Summary

Aether modeled BHUH's aggregated utility gas supply portfolio twenty years forward in time, using several six different hedging scenarios and nine different market price scenarios. Aether used a Base Case price scenario to represent the acquisition cost of short-term hedges and the Illustrative Reserves Price scenario for long-term gas production. Aether performed stress tests on the portfolio using nine different price scenarios. The objective was to examine the impact of additional hedging in different types of market situations.

The long-term hedges executed at the Illustrative Reserves Price scenario would provide price protection to customers if market prices were to rise to the higher price scenarios. As the level of hedging increased, the range in potential outcomes became narrower. Moreover, the higher the hedged volume, the greater the price protection against rising prices will be. If prices declined, there was an opportunity cost to locking in long-term hedges, but this occurred in only two of the ten price scenarios. The opportunity cost should be considered in light of the risk reduction associated with rising prices, the relative rate level compared to historical rates, and the benefits of rate stability and greater rate predictability.

Methodology

A. Model Description

The model is a discounted cash flow model that extends over a period of twenty years. The load service area is divided into seven regions and the load demand was supplied from production and open market purchases depending upon the scenario. There are three forward price indexes that were available: (a) Henry Hub, (b) Colorado Rockies (c) NNG Ventura, and (d) Southern Star. The model allows the user to change the pricing index for each region as well as the hedging index. In any given scenario, all open market (i.e., non-hedged) purchases are executed at the selected price scenario as if that were the market index price. There are four methods used to mitigate price volatility: (a) Gas Storage, (b) Fixed Price Hedging (using Futures) (c) Call Options and (d) natural gas production. Hedges for a given month are assumed to be executed at the Base Case price scenario for short-term hedges and the Illustrative Reserves Price scenario for long-term production for the given month at the location. The allocations are made accordingly for each utility.

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B. Gas Demand

The gas demand forecasts are from BHUH's long-term demand forecasting for the natural gas utilities and the electric utilities' gas demand. The 2016 load forecast of 72.6 Bcf represented the gas demand for Colorado Gas Utility, Colorado Electric Utility, Kansas Gas Utility, Iowan and Nebraska Gas Utility, Nebraska Out State Gas Utility, and Cheyenne Fuel, Light and Power Wyoming Gas and Wyoming/South Dakota Electric. This demand forecast was escalated over the twenty year period in accordance with BHUH's long-term load projections. By 2035, the total annual gas demand was estimated to reach 83.9 Bcf.

C. Discount Factor

The model requires a discount factor to convert the nominal gas supply costs into a net present value amount. Because gas reserves are a long-term asset, Aether applied a blend of 60% equity component based upon BHUH's authorized return of equity of 9.86% and 40 percent long-term debt cost of 4.5% for a weighted cost of capital of 7.72%.

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D. Price Scenarios

Aether used [redacted]; a Base Case Price scenario; an Illustrative Reserves Price scenario; and an Extreme High Price scenario. These are summarized below and described in more detail in Appendix C – Detailed Explanation of Forward Price Scenarios:

- [redacted] (nominal dollars)
- One natural gas price forecast from EIA's Analysis of the Impacts of the Clean Power Plan, May 2015, "Clean Power Plan Base Policy (CPP)" (nominal dollars)
- [redacted] nominal dollars)
- [redacted] (nominal dollars)
- Illustrative Reserves Price scenario, provided by BHUH as a theoretical cost of acquiring gas production (not based upon any specific property or potential acquisition) (nominal dollars)

- Extreme High price scenario that is two times the Base Case price scenario (nominal dollars)[74]

In order to make the results from different price scenarios comparable, certain adjustments were [redacted]. Note, because the Base Case price scenario [redacted], the distinctions between these three forecasts are hard to discern:

Figure 62 – Illustrative Reserves Price Scenario and Ten Henry Hub Price Scenarios

[redacted]

[74] The Extreme High Price scenario is not a forecast, but a price scenario Aether added to incorporate price escalation, based upon historical price appreciation in the period of 1988 to 2008, prior to the shale gas production expansion. This is not a price forecast, but a price scenario developed to test the potential impact on gas supply costs if the forward market price appreciated at a rate of growth seen in historical periods.

E. Regional Pricing (Basis Differential)

The utilities' physical gas supply requirements are in the states of CO, WY, KS, NE and IA. The Henry Hub price forecasts were used to value the short-term hedges BHUH would typically execute at Henry Hub. In order to model the regional risk exposure of BHUH's portfolio, the load, gas storage, fixed price physical supply, and the gas production were valued at three regional markets (Colorado, Northern Natural Ventura, and Southern Star).

[redacted], but not for Ventura and Southern Star. And the rest of the price scenarios were Henry Hub prices. To generate regional basis prices for the scenarios without regional prices, Aether used the forward basis market price from the CME Basis Futures for Colorado CIG Rockies, Southern Star, and Ventura, as of September 16, 2015 for the period of January 2016 to December 2020. The basis from 2020 was carried forward for the years 2021 to 2035.

F. Monthly Price Granularity

BHUH's natural gas demand is heavily weighted to winter months because it is a winter-peaking system. Therefore, the annualized price forecasts were adjusted to monthly price increments, using the monthly price relationships of the CME Henry Hub futures prices and the historical monthly demand volumes

G. Current Hedging Instruments

BHUH's current hedging instruments - storage, call options, futures, and fixed price physical contracts- are included in the portfolio model. Storage is modeled with ratable summer injection volumes and ratable winter withdrawal volumes. As a hedging instrument, it is only depicted for the current winter season, given that BHUH does not forward hedge gas injection volumes. The fees for storage and fuel losses are not included in the model, only the purchase cost of the storage. Natural gas storage is modeled using the market prices for the three market hubs (Colorado Interstate Gas, Northern Natural Ventura and Southern Star). The call options are modeled as Henry Hub call options and the model has a volatility curve input that can be changed for different volatility levels. The futures are valued at Henry Hub and the fixed price physical contracts are modeled at one of the three market hubs.

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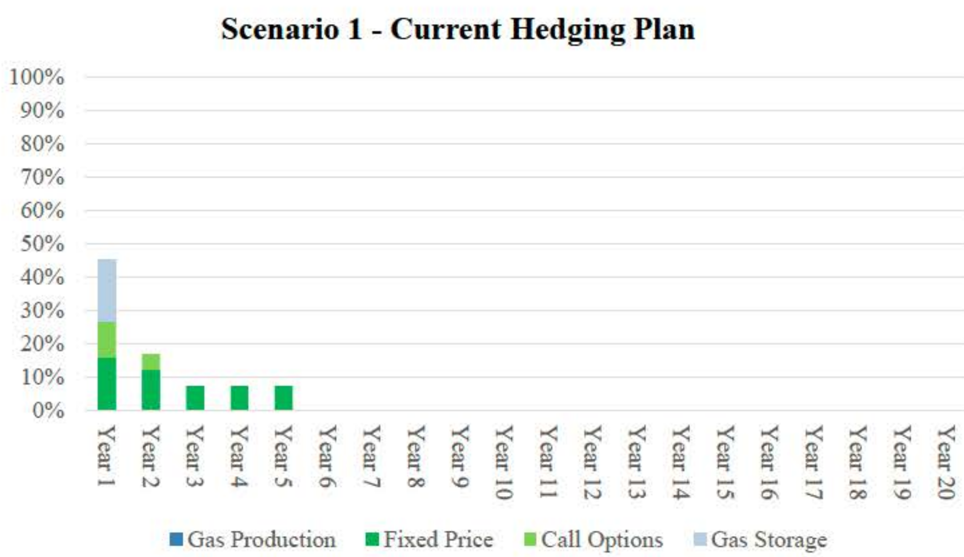
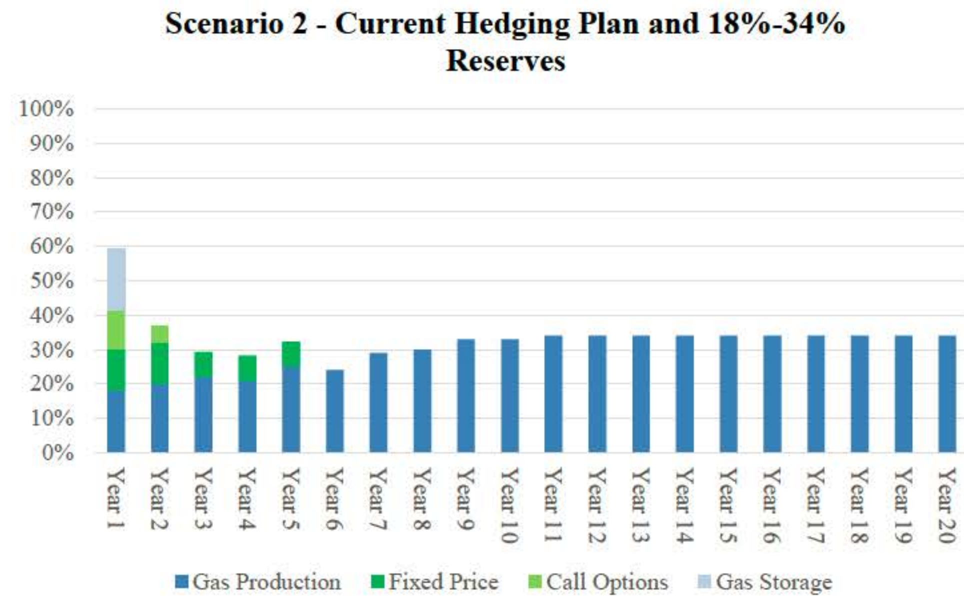
H. Hedging Scenarios

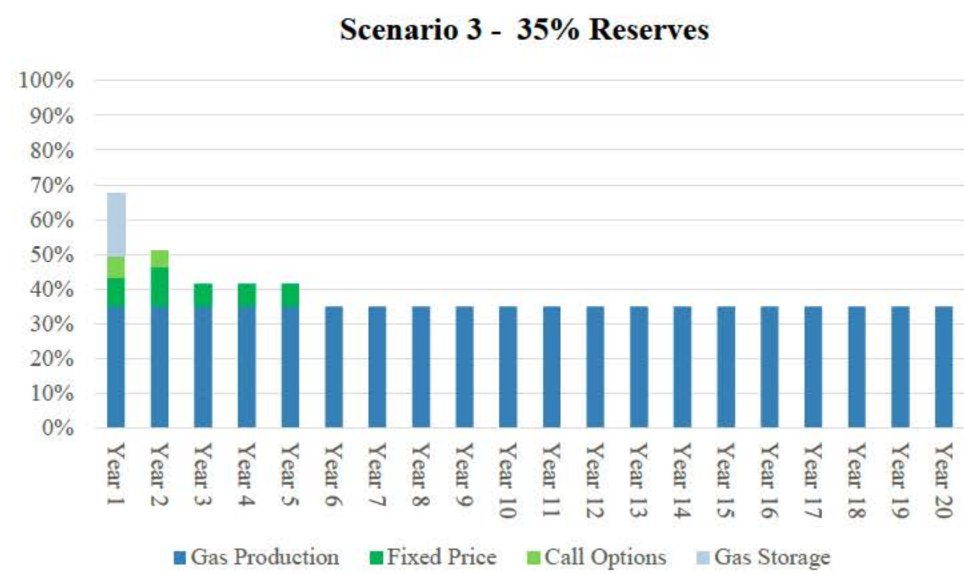
The six hedging scenarios tested are titled below, followed by graphical representations by instrument and by year.

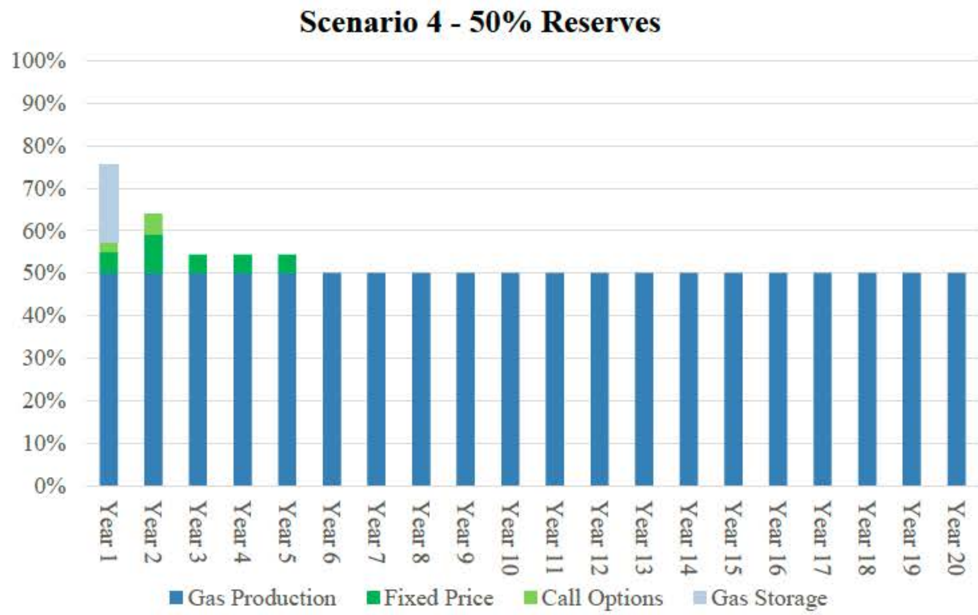
Figure 63 – Hedging Plan Scenarios

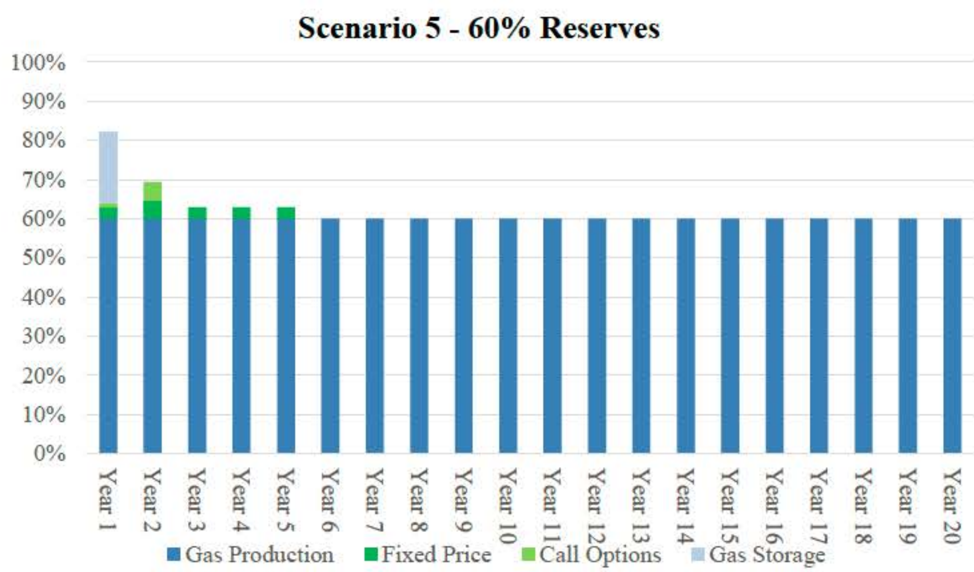
- Scenario 1 - Current Hedging Plan
- Scenario 2 - Current Hedging Plan and Gas Reserves starting at 18% in Year 1 and rising to 34% by Year 11 and staying at 34% through Year 20
- Scenario 3 - Short-term, Medium-term and Gas Reserves 35% long-term
- Scenario 4 - Short-term, Medium-term and Gas Reserves 50% long-term
- Scenario 5 - Short-term, Medium-term and Gas Reserves 60% long-term
- Scenario 6 - Short-term, Medium-term and Gas Reserves 75% long-term

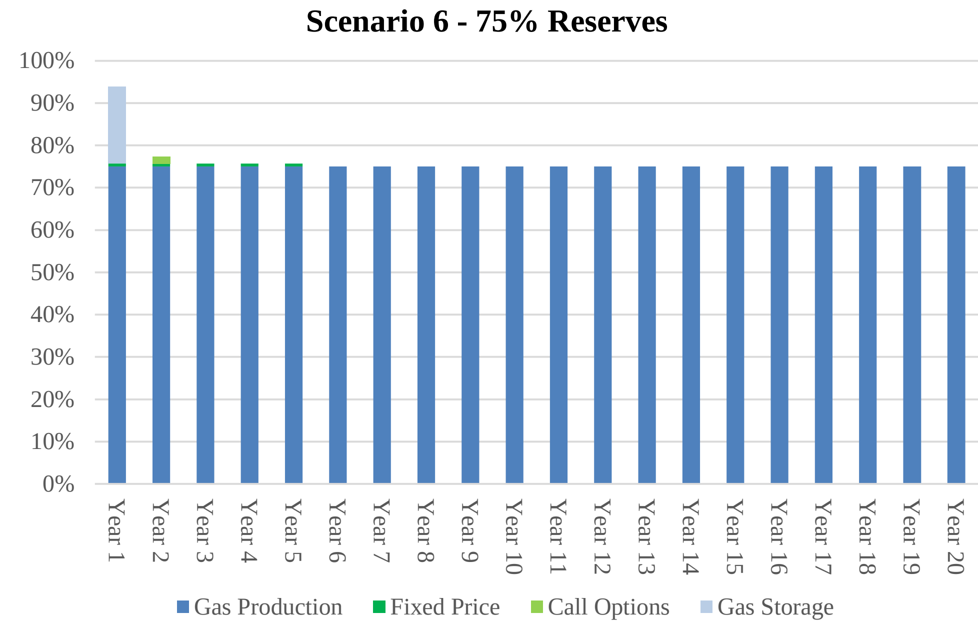



Scenario 2 - Current Hedging Plan and 18%-34% Reserves
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Year 1
Year 2
Year 3
Year 4
Year 5
Year 6
Year 7
Year 8
Year 9
Year 10
Year 11
Year 12
Year 13
Year 14
Year 15
Year 16
Year 17
Year 18
Year 19
Year 20
Gas Production
Fixed Price
Call Options
Gas Storage


Scenario 3 - 35% Reserves
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Year 1
Year 2
Year 3
Year 4
Year 5
Year 6
Year 7
Year 8
Year 9
Year 10
Year 11
Year 12
Year 13
Year 14
Year 15
Year 16
Year 17
Year 18
Year 19
Year 20
Gas Production
Fixed Price
Call Options
Gas Storage


Scenario 4 - 50% Reserves
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Year 1
Year 2
Year 3
Year 4
Year 5
Year 6
Year 7
Year 8
Year 9
Year 10
Year 11
Year 12
Year 13
Year 14
Year 15
Year 16
Year 17
Year 18
Year 19
Year 20
Gas Production
Fixed Price
Call Options
Gas Storage


Scenario 5 - 60% Reserves
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Year 1
Year 2
Year 3
Year 4
Year 5
Year 6
Year 7
Year 8
Year 9
Year 10
Year 11
Year 12
Year 13
Year 14
Year 15
Year 16
Year 17
Year 18
Year 19
Year 20
Gas Production
Fixed Price
Call Options
Gas Storage

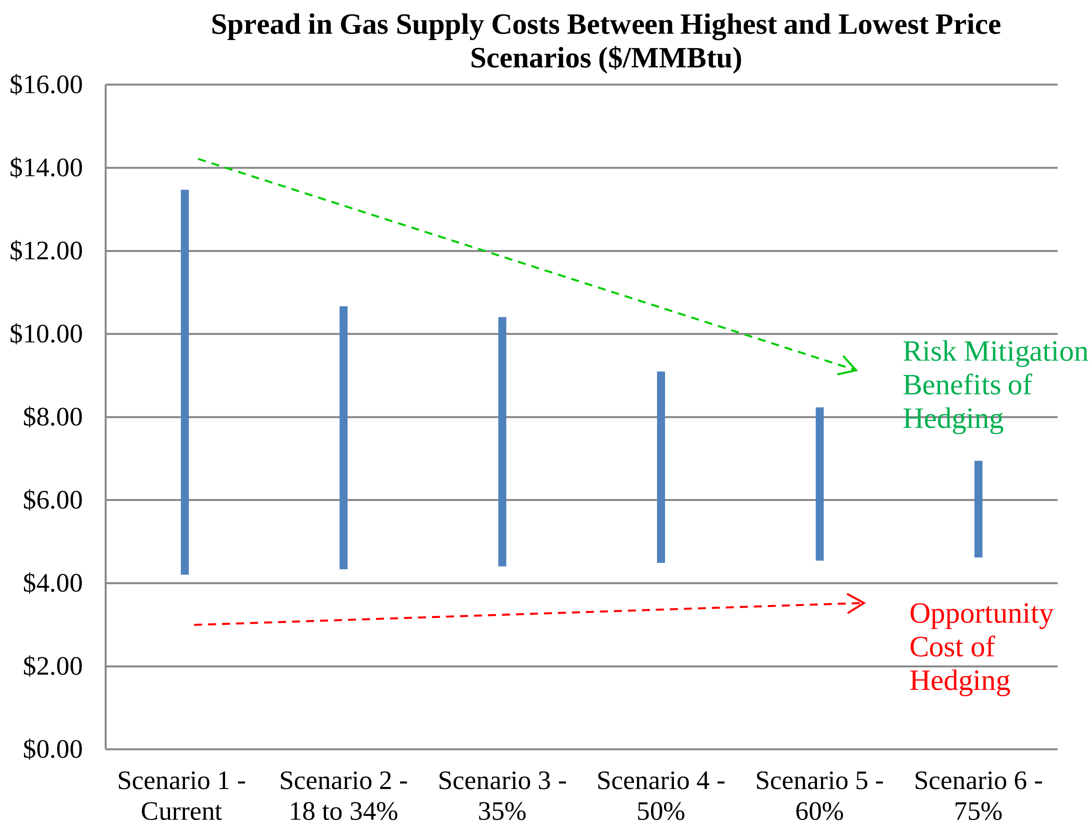


Modeling Results

The results from the portfolio modeling are shown in the figure below. The candlestick chart (vertical lines) in the graph below depicts the range in gas supply costs for each hedging scenario. The higher the percentage hedged of the portfolio, the narrower the spread in gas supply costs across all the price scenarios. This illustrates that the higher the percentage hedged, the more stable customer gas supply costs.

The chart is also helpful for viewing the trade-off between price volatility mitigation and potential opportunity cost. The green arrow directionally shows the mitigation achieved with greater percentages of hedging – the higher the hedging percentage, the greater the mitigation against the higher price scenarios. The red arrow directionally shows the potential opportunity cost of hedging greater percentages of the portfolio. Opportunity cost represents the difference between the hedged cost and lower market prices (represented by the lower price scenarios). The opportunity cost in the portfolio modeling is much smaller than the risk mitigation achieved. This is because the Illustrative Reserves Price scenario is a low price relative to all but two of the other price scenarios in the model and the difference between those and the Illustrative Reserves Price scenario is not large. The numerical values for the range in gas supply costs resulting from the six hedging scenarios are illustrated in the table below the graph.

Figure 63 – Graphical and Tabular Results of the Portfolio Modeling (Average Cost)



[redacted]

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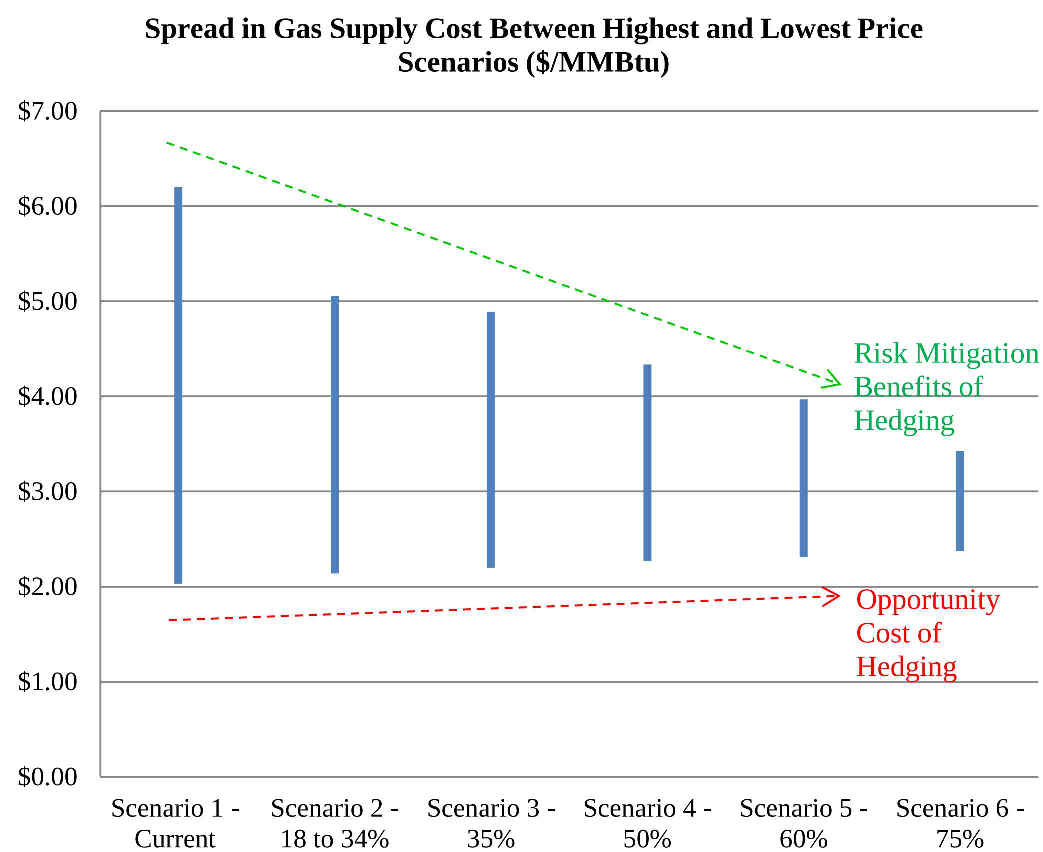
The table summarizes the twenty year gas supply cost on an average cost. The greatest range in potential gas supply cost occurs in in the first hedging scenario representing BHUH's current hedging program. The spread between the highest and lowest gas supply outcome is $9.27 / MMBtu ($4.20/MMBtu in the [redacted] compared to $13.46/ MMBtu in the Extreme High). In contrast, this spread narrows considerably to $2.33/MMBtu in the highest hedging scenario of 75% long-term production ($4.20/MMBtu [redacted] scenario compared to $13.46/ MMBtu in the Extreme High).

The following figure provides the same information as above, except the gas supply costs are reported as a net present value. The values in the table illustrate the gas supply cost associated with each hedging scenario and each price scenario. The net present value analysis shows the same relationship – a higher hedging percentage over a long-term horizon provides gas supply cost stability and protection against rising prices for the utilities' customers.

Figure 64 – Graphical and Tabular Results of the Portfolio Modeling (Net Present Value Cost)



[redacted]

Aether's analysis treated the gas production as a long-term fixed price commitment, hedged at the Illustrative Reserves price. The model compared the Illustrative Reserves price to the other price scenarios to illustrate the range in potential risk reduction and opportunity cost under the different hedging scenarios. The ten price scenarios included a variety of different price forecasts and were intended to show a reasonable range of potential outcomes.

Conclusion

The benefits of long-term hedging are as follows: 1) the reduction in the range of gas supply costs; 2) the provision of more price stability; and 3) the mitigation against rising prices. There is an opportunity cost if prices decline below the hedge price, although this was minimal in the portfolio modeling results. It should be noted that the portfolio modeling treated the gas reserves as a fixed price commitment, which is a conservative modeling approach. In a "drill to earn" structure where BHUH would participate in future drilling, the initial investment in producing properties is similar to a fixed price contract with volumes declining over time, but the incremental production that comes from commitment of new capital to new drilling is more akin to a long-term call option. BHUH would have the option to invest additional capital into new drilling. If forward prices did not justify additional drilling, BHUH could decide not to invest additional capital in drilling and extraction.

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Part 5 – Conclusions and Recommendations

Conclusions

In recent years, most U.S. utility commissions have continued to support utilities' gas hedging programs, but in some cases have encouraged utilities to work with interested parties to update hedging programs designed in the early 2000s to adjust for more recent market events. There has also been a notable shift among some commissions to support long-term hedging opportunities for rate stability purposes, given recent lower natural gas prices.

BHUH requested Aether review its current hedging program and supply recommendations for program enhancements. The first question was whether long-term hedging would make sense for the utilities' customers. The second was what percentage of long-term hedging would be appropriate in its gas supply portfolio. And the third question was how a long-term hedging strategy could be integrated with the current short-term gas utilities' hedging programs and the five year Colorado electric utility hedging program.

To answer these questions, Aether conducted several types of analysis. First it assessed BHUH's current hedging program. Then it reviewed different types of hedging instruments BHUH could consider. From there, it looked at the fundamental market drivers impacting natural gas supply, demand, and prices. Lastly, Aether conducted "what if?" analyses to test the effect of different hedging programs across different market scenarios to understand the potential impact on future gas supply costs.

Aether's review of BHUH hedging program is detailed in <u>Part 1 – Current Gas Supply Portfolio Review</u>. Aether examined BHUH's hedging goals, hedging program design, the risks mitigated, the time frame and percentage hedged, the protocols for executing hedges, the instruments used, and how the hedging program's success is measured. With respect to its short-term hedging for the gas utilities, Aether found BHUH to have a hedging program that helps protect customers against seasonal price spikes. With respect to the Colorado Electric utility, electric customers benefit from a longer-term hedging program.

BHUH's hedging program for its gas and electric utilities is clearly articulated. Aether's review indicates the current hedging program is consistent with the regulators' policies. Progress toward meeting hedging goals is monitored carefully and results are shared with Commission staff. Additionally, the hedging program is transparent and well-managed. The hedging goals are consistent across its gas utilities, tailored slightly differently for each commission's specific design requests. For the gas utilities, the hedging focus is on the upcoming one to two winters. For the Colorado Electric utility, the hedging declines from 50% to 10% over a five year horizon.

The hedging instruments are also consistent with the hedging goals and managed carefully. Hedging is executed with a blend of storage, fixed price hedges, and call options hedges. The current hedging practices and hedging program are consistent with BHUH's gas supply goals to: mitigate price volatility (on a short-term basis) and to provide a high level of reliability. The short-term fixed price hedges, storage and options are tools to manage price risk during the winter season. Additionally, gas storage and call options help BHUH balance supply against short-term load increases and decreases. However, the current gas utilities' hedging program does not mitigate price volatility outside of the winter.

While the current gas utilities' hedging program protects customers against short-term market risks, it does not protect customers from medium-term and long-term market price risk exposure. In contrast, the hedging program for the Colorado electric utility differs from that of the gas utilities because the hedging program extends farther forward into time (five years). Hedging on a seasonal basis protects against short-term price spikes but it does not provide stable rates year over year as does medium-term and long-term hedging. When a utility employs longer-term hedging, there is greater opportunity to hedge price exposure over a period of several gas supply years.

Long-term hedging can be combined with short-term and medium-term hedging to provide more long-term rate stability while also managing short-term market volatility. This can be accomplished through how much is hedged in each year and what instruments are used. In the recommendation that follows this section, Aether described several ways to integrate long-term hedging with the current hedging programs.

In Part 2 – Gas Supply Hedging Options, Aether provided descriptions of illustrative hedging instruments appropriate for medium-term and long-term hedging. These included rate mechanisms, physical storage, physical fixed price contracts, financial instruments, and gas production (volumetric production payments and reserves). In terms of hedging long-term with a contract for future delivery as opposed to owning gas production, there are important considerations. There can be limited market liquidity in long-term contracts and there may be material counterparty and credit risks. In contrast, with gas reserves, the owner holds title to the asset and can control when additional investments are made.

Given that long-term hedging is a significant commitment to enter into on behalf of customers, it is important that a number of factors are considered prior to entering into long-term hedges. Part 3 – Long-Term Factors and Opportunity Assessment includes several perspectives from which to consider the relative value of a long-term hedge. It is important to consider the price value the investment offers. Further, an assessment of natural gas supply and demand drivers can offer additional confirmation that a decision to invest in gas production is reasonable.

Lastly, it is important to conduct portfolio analysis to understand the implications of expanding a utility's hedging program. This can be done by testing different types of hedging strategies for different possible market outcomes. In Part 4 – Portfolio Modeling, Aether tested BHUH's gas portfolio under six different hedging scenarios: if BHUH did no additional hedging beyond its current hedging (Scenario 1) and if it entered into five different expanded hedging scenarios (Scenarios 2-6). The analysis examined the financial impact of hedging under the six different hedging scenarios using nine separate price scenarios.

The starting assumption was that the short-term hedges would be acquired at the Base Case Price scenario, but that the long-term gas production would be acquired at the Illustrative Reserves Price scenario. The assumed production cost provided to Aether by BHUH is a theoretical production price reflecting an initial investment and an on-going drilling program that provides efficiencies and cost savings that more than off-set the rate of inflation.

The results from the portfolio modeling are shown in the figure below. The candlestick chart (vertical lines) depicts the range in gas supply costs for each hedging scenario. The higher the percentage hedged of the portfolio, the narrower the spread in gas supply costs across all the price scenarios. This illustrates that the higher the percentage hedged, the more stable customer gas supply costs.

The chart is also helpful for viewing the trade-off between price mitigation and potential opportunity cost. The green arrow shows the mitigation achieved with greater percentages of hedging – the higher the hedging percentage, the greater the mitigation against the higher price scenarios. The red arrow shows the potential opportunity cost of hedging greater percentages of the portfolio. Opportunity cost represents the difference between the hedged cost and lower market prices (represented by the lower price scenarios). The opportunity cost is much smaller than the risk mitigation achieved because the Illustrative Reserves Price scenario is a relatively low price. There is a small price differential between the Illustrative Reserves Price scenario and the lower price scenarios.

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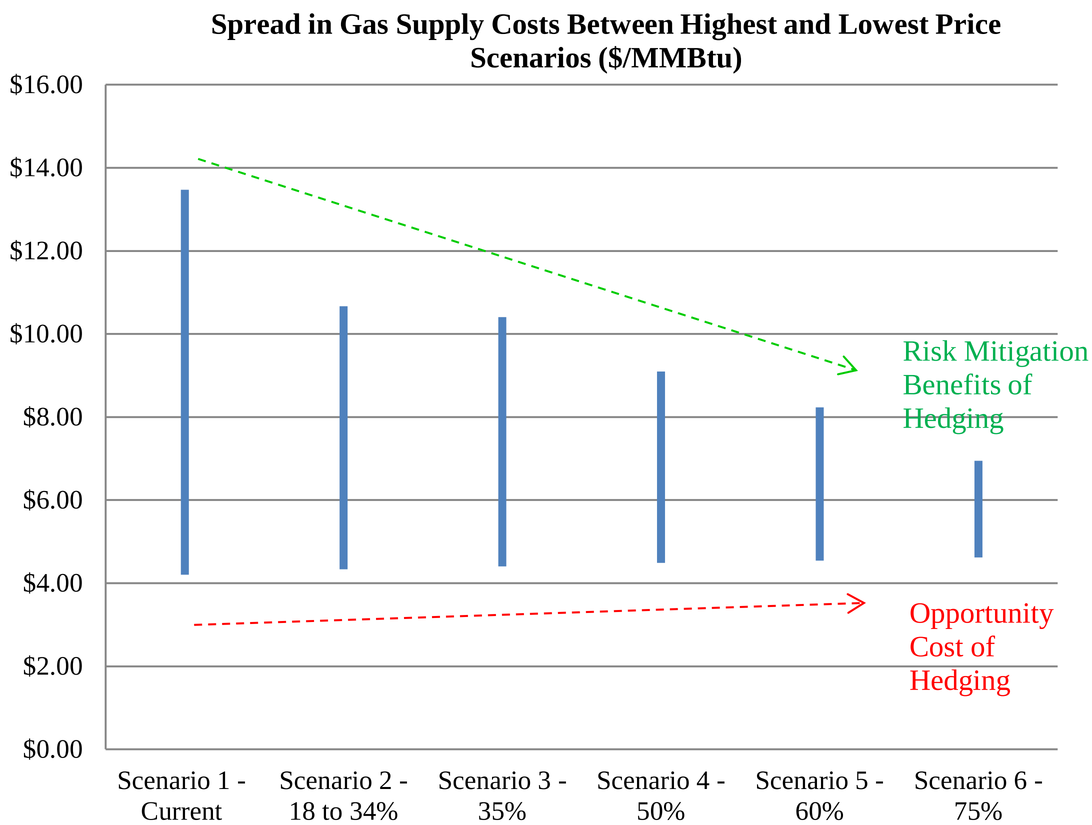
Figure 65 – Graphical and Tabular Results of the Portfolio Modeling (Average Cost)



[redacted]

The table summarizes the twenty year gas supply cost on an average cost. The greatest range is potential gas supply cost occurs in in the first hedging scenario representing BHUH's current hedging program. The spread between the highest and lowest gas supply outcome is $9.27 / MMBtu ($4.20/MMBtu in the [redacted] compared to $13.46/ MMBtu in the Extreme High). In contrast, this spread narrows considerably to $2.33/MMBtu in the highest hedging scenario of 75% long-term production ($4.20/MMBtu in the [redacted] compared to $13.46/ MMBtu in the Extreme High).

Based upon the portfolio modeling results, long-term hedging offers more rate stability over time and provides mitigation against rising market prices. The higher the volume hedged long-term, the narrower the range in gas supply costs and the greater the price protection.

Recommendations

Hedging plans are customized across North America utilities, with different risk tolerances, varying program objectives, and alternative ways of measuring success. There is no single standard for hedging, which means a utility's hedging program design is chiefly shaped by its risk management objectives, supply management goals, and regulators' policy guidance.

Seasonal hedging is a valuable element in a hedging program because it focuses on protecting customers from a seasonal spike in market prices. But seasonal hedging does not provide extended hedging protection, for it leaves customers vulnerable to upward market trends that occur outside of the winter period and over a period of time. Many utilities employ a three to five year hedging program, similar to how BHUH hedges its Colorado Electric gas supply needs over a five year horizon. Moving to an expanded hedging horizon for the gas utilities provides more rate stability year over year for customers. Long-term hedging can extend the benefits farther forward in time. When market conditions are attractive, it can be beneficial to customers for the utility to hedge long-term in its portfolio.

Aether recommends BHUH extend the duration of the hedging program and increase the percentage of hedging. There are opportunities to lock in long-term supply costs at attractive levels relative to historical gas prices. Further, there is significant uncertainty about future market developments. New natural gas demand may be driving market prices which is a material shift from recent years when supply trends greatly influenced market price. Lastly, the portfolio modeling confirms that adding long-term hedges and increasing the percentage of the portfolio hedged would provide greater rate stability by reducing rate volatility and protecting against rising market prices.

Aether considered BHUH's proposed Cost of Service Gas proposal. If reserves can be acquired at an attractive price, the strategy would be even more consistent with the three gas supply goals and would offer supply diversity and rate stability. BHUH's Cost of Gas Service strategy to procure long-term supply would contribute to long-term rate stability and reliable supply. However, a gas reserve investment is a material undertaking from a resource and cost perspective. Therefore, it is important that the investment makes sense as a risk reduction strategy in addition to a security of supply strategy.

From a pricing perspective, natural gas prices are currently at historical lows, but there are many indications prices will be rising. If gas production could be acquired at attractive prices today because of the low spot market, the acquisition could provide rate stability at attractive price levels relative to historical costs. From a supply perspective, the evolving shale technology has enabled the U.S. gas industry to bring new gas supply to market faster and at lower cost than through conventional drilling. This supply growth has caused gas prices to drop over the past seven years, from which consumers have benefited greatly. The supply side is stable today and the technology and cost to produce shale gas are well understood. But current prices are at close to break-even levels for producers. Prices will likely need to rise to encourage production growth to meet future demand increases.

At the same time, there is significant growth in gas demand from increased gas generation fuel (in response to environmental regulation), gas as a fuel in the transportation sector, and a new era of liquefied natural gas (LNG) exports from the U.S. into global markets. There is a great deal of uncertainty regarding the scale of this demand growth. Aether examined the assumptions in EIA's Reference Case, which serves as a mid-point in the range of forecasts used for the portfolio modeling. The Reference Case has lower LNG export estimates than what other forecasting companies are projecting. Notably, the EIA Reference Case does not reflect the potential increase in gas demand that could arise as a result of the EPA's Clean Power Plan.

Aether looked at the Illustrative Reserves Price scenario from several perspectives: a comparison of the forward market price to historical market price and historical customer gas supply costs; a comparison of North American natural gas prices to crude prices; and a comparison of North American natural gas prices to global natural gas prices. Aether reviewed supply-side and demand-side market fundamentals as well. The supply side fundamental market assessment factors included: 1) domestic production trends; 2) Canadian production and exportable surplus; 3) gas producer economics; and 4) reserve replacement trends. Demand-side market fundamental analysis included: 1) electric sector gas demand growth as a result of coal plant retirements; 2) demand for natural gas as a transportation fuel for trucking, maritime, and rail freight; and 3) exports from North America. These are summarized in the figure below:

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Figure 66 – Factors Supporting Long-Term Hedging

Customer Price	Gas production hedging can stabilize rates for customers at reasonable costs relative to historical costs
Historical Price Context	Recent historical low gas prices may not continue and may well revert to higher prices seen historically because of new gas demand
Crude Oil vs. Natural Gas	Despite lower crude oil prices, many producers still prioritize crude exploration and production over natural gas; U.S. LNG contracts may be shifting from a crude oil benchmark to blend of crude oil and natural gas benchmarks
Break-even Cost	Current market price is not much higher than the break-even cost of production for shale production
Gas Production Trends	Low producer profitability, shrinking capital investment in gas drilling and modest gas reserves replacement trends indicate prices may need to rise to encourage greater investment
Net Imports	Canada has less exportable surplus to send to the Lower 48 states and Mexican demand is forecasted to continue to grow
Transportation Demand	North American demand is growing through expanding CNG/LNG transportation demand
Environmental Regulation	Current and proposed regulation would result in still more gas generation and renewable energy additions
Comparative Pricing	Natural gas is attractively priced relative to other energy sources
U.S. Gas Prices	U.S. natural gas is attractively priced to destination LNG markets
LNG Plants	U.S. brownfield LNG export terminals have a cost advantage compared to greenfield plants elsewhere and a number of facilities have already received approvals
LNG Contracting	Most of the approved LNG export capacity has associated long-term contracts with large international LNG traders and consumers

The fundamental analysis is more supportive to prices rising, rather than falling. The amount that prices can drop is finite, to the level where producers do not invest new capital to replace reserves and where they might shut-in production. Theoretically, prices have no limit on how far up they can move. That means there is nothing to stop prices from rising higher than the high price scenarios used in Part 4 – Portfolio Modeling. Additionally, the Illustrative Reserves Price scenario is below levels at which natural gas prices have traded in the past.

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BHUH should pursue long-term hedging and provide long-term rate stability to customers. The Cost of Service Gas proposal is consistent with all of BHUH's gas supply goals to: 1) provide reasonably priced natural gas; 2) provide a high level of reliability; and 3) mitigate price volatility. Investing in gas production provides greater long-term rate stability at levels attractive relative to historical rates.

The portfolio modeling treated gas reserves investment as a long-term fixed price resource modeled at the Illustrative Reserves price. In fact, the Cost of Service Gas proposal has more flexibility, where BHUH would have the option but not the obligation to pursue incremental drilling dependent upon the forward market prices at that time. Given BHUH's gas supply objectives, the shifting fundamentals from a supply-driven market to a demand-driven market, and the support its production and exploration affiliate can provide, Aether recommends BHUH seek approval to invest in long-term gas production to try to lock in attractive prices for customers.

In terms of how much to hedge, Aether recommend a minimum of 35% with a target of up to 50% hedged with gas reserves. The range in percentage of hedging with gas reserves among other utilities is quite varied- ranging from 15% by Sacramento Municipal District to 65% by Questar Gas. The "up to 50%" recommendation for reserves acquisition is based upon several factors. First, a meaningful volume commitment will bring greater economies of scale than a smaller program. Additionally, the COSG Program will take a great deal of management time to execute and manage this effort, as well as Commission time to monitor and assess the results. The effort involved would not make sense to pursue if it did not provide meaningful hedging protection to customers.

The reason for limiting the long-term hedging to up to 50% of demand is that larger hedging percentages do not provide much flexibility to BHUH if market conditions change. On one hand, increasing the hedging percentage narrows the range in gas supply costs. But, while a higher percentage would provide additional rate stability and confidence around the gas supply cost, there is a point where committing to high percentage of gas reserves leaves little room for future portfolio management flexibility or innovation in the future. For example the combination of 75% hedged and storage would aggregate to close to 100% for the upcoming winter, leaving no opportunity to use other tools such as call options.

There are two key elements to the Cost of Service Gas proposal that support an up to 50% hedging recommendation. First, BHUH has the benefit of the knowledge and expertise of an exploration and production affiliate, which is unusual among gas and electric utilities. Many utilities are unfamiliar with the opportunities and risks associated with owning gas producing properties, but BHUH would benefit from the experience of its exploration and production affiliate, that could advise on key issues and potentially act as the producer operator.

Second, unlike other utility reserve acquisition programs that Aether has reviewed, BHUH is proposing a performance benchmark that should further reduce the risk for customers and align interests between customers and the shareholders. BHUH is proposing that its allowed return on equity ("ROE") be decreased by 100 basis points if there is a Hedge Cost associated with production, placing risk on BHUH and decreasing gas supply costs for customers. Given BHUH's authorized ROE is 9.86%, this would represent a potential penalty of 10% to the ROE, which is not inconsequential from a percentage standpoint. The proposal has an incentive on the other side by increasing the allowed ROE by 100 basis points if there is a Hedge Credit.

If BHUH expands its short-term program to include long-term hedges, it will be important to develop an integrated approach to link together the short-term, medium-term and long-term hedging. The starting point is to develop a long-term target for reserves, using both qualitative and quantitative analysis. Following this, the short-term and medium-term instruments would be layered in to provide greater short-term market risk management flexibility.

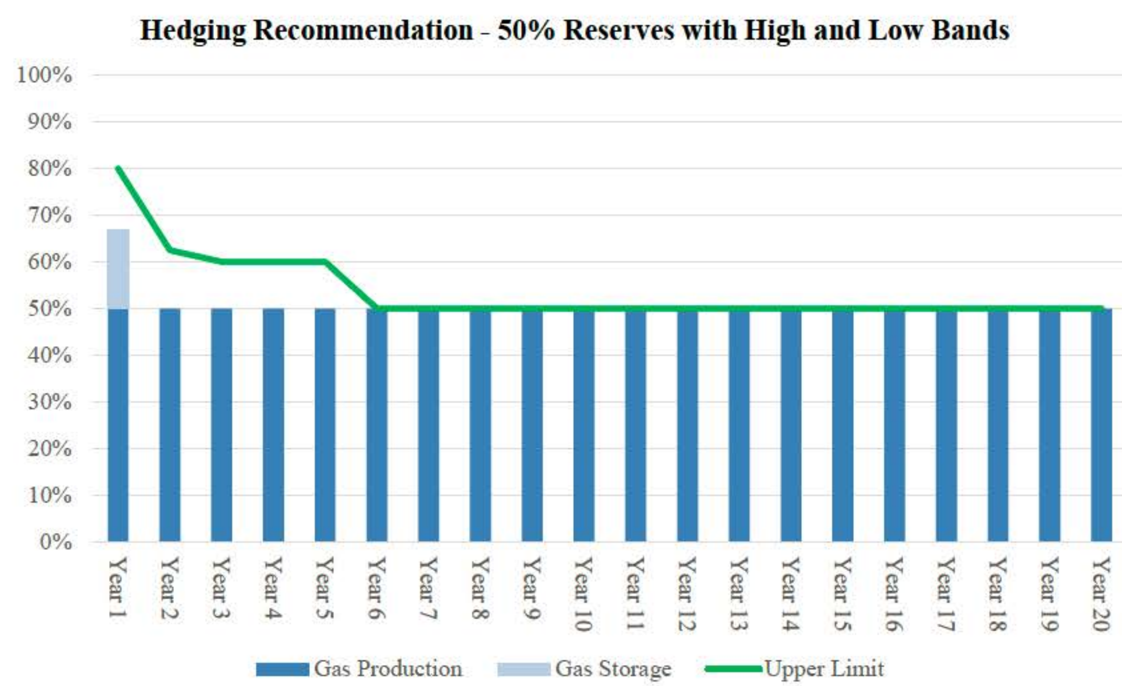
The gas reserves would serve as the base of its hedging program, upon which short-term and medium-term hedges would be layered. BHUH would set hedging targets by year that combined reserves with short-term and medium-term hedges. It is conventional in utility hedging programs to hedge a higher percentage in the first year and for the percentage to decline in future years. This is because the greatest market price volatility is in the short-term, and this is where the higher percentage of hedging is appropriate. Therefore, Aether recommends a staggered approach looking forward into the future, where the percentage of hedging declines over time.

For example, in Year 1, BHUH would have short-term, medium-term and long-term hedges in place to aggregate to a target amount. The hedging amount for Year 2 would include medium-term and long-term production aggregating to a lower target than Year 1. The decline would similarly apply for Years 2-5 with declining percentages each year, until Year 6 where the gas production would be the only forward hedge. This would be done on a rolling basis, so that at any given point in time, BHUH's gas supply portfolio would have this shape looking forward into the future. As one year rolled off, then new short-term and medium-term hedges would be executed to maintain the hedging plan targets.

On an annual basis, BHUH hedges 27% - 55% its utilities' gas requirements for the upcoming winter using storage, short-term fixed price, and call options. Instead of having fixed targets for hedging, Aether recommends BHUH set a hedging band for the short-term and medium-term horizon. Hedges would be executed within the pre-determined range based upon changing market conditions. The range would be set with a minimum level and a maximum level by year, and BHUH would hedge between the minimum and maximum levels based upon forward fundamental and technical market analysis.

The reserves production and the storage commitments would be the minimum amount. In terms of prioritization, storage is a critical balancing tool for short-term demand variability and should be maintained to provide operating reliability, system flexibility, and winter peaking price protection for customers. The maximum amount would include call options and short-term fixed price contracts. After the gas reserves and the gas storage, the call options would be the next priority. BHUH could continue to use call options to insure against short-term price spikes during winter months. The lowest priority for additional short-term hedging would be short-term fixed price, since the gas reserves production is similar to a fixed price hedge. The graph below is a pictorial representation of how an integrated plan with hedging bands could be accomplished.

Figure 67 – Illustrative Integrated Short-Term, Medium-Term and Long-Term Hedging Plan



Since BHUH currently has no natural gas reserves and it may take one than one acquisition to build to 50% of weather normalized gas supply needs, a transition plan will be required to move from the current hedging program to the one illustrated above in Figure 69. With each subsequent acquisition, BHUH would rely increasingly less on short-term and medium-term hedging. The graphs for scenarios 1 through 3 in Part 4 – Portfolio Modeling help illustrate how BHUH's portfolio might look during the acquisition phase. As BHUH entered into new acquisitions, it could submit a revised short-term and medium-term hedging plan to the Commission, illustrating how hedges for the next one to five years would be integrated with the natural gas production.

Appendix A – Illustrative Utility Hedging Through the Acquisition of Reserves

<u>Florida Power and Light</u>

In December 2014 the Florida Public Service Commission (PSC) approved Florida Power & Light's (FPL) request to invest in natural gas drilling projects in Oklahoma and recover its investment through the fuel cost recovery clause. FPL pursued this strategy to hedge fuel for its natural gas-fired power plants. The initial $191 million investment in a joint venture with PetroQuest Energy Inc. is projected to save customers $52 million over the life of the wells.[75] At the peak of production, FPL is expected to receive about 46 Mmcf/day, with a total life of 137 Bcf from the Woodford shale. FPL purchases up to 2 Bcf/day gas supplies for its generating plants, and the long-term purchase will compliment FPL's current hedging program.[76]

In the joint venture, PetroQuest is responsible for the well administration and operations. Annual costs associated with the project are trued up during the annual cost recovery clause hearings. FPL's affiliate NextEra Energy Resources established a unit called USG Properties Woodford I LLC to be the partner with PetroQuest. If the commission had not approved the transactions for FPL's utility customers, the transaction would have remained with NextEra. FPL has requested the PSC approve guidelines for future natural gas production projects, so that FPL can quickly act on future investment opportunities. In June 2016, the PSC said it would review the guidelines for future gas reserves projects every three to five years. The Commission limited the maximum hedging percentage to 20 percent and the annual project investment cap to $500 million.

<u>Northwest Natural Gas (Gas) – Oregon, Washington (the information below relates to Oregon)</u>

As a part of its PGA mechanism in Oregon, prior to the commencement of the rate year, Northwest Natural Gas (NW Natural) selects either a sharing mechanism of 10% company /90% customers or 20% company/ 80% customers of the differential (high or lower) between filed PGA costs and actual gas costs. NW Natural hedges approximately 75% of the annual gas

[75] Florida Public Service Commission, News Release: PSC Approves FPL Gas Reserve Investment Recovery; Stabilizes Fuel Costs for Customers, December 18, 2014, http://www floridapsc.com/home/news/?id=1218 (Accessed: June 2015)
[76] *Florida Electric Utility going to Wellhead for Better Gas Deal*, Joe Fisher, Natural Gas Intelligence, June 25, 2014, http://www naturalgasintel.com/articles/98823-florida-electric-utility-going-to-wellhead-for-better-gas-deal, (Accessed: June 2015)

requirements, employing both financial and physical hedges. For the rate year 2012-2013, the composition was 47% financial swaps and option contracts and 28% physical gas supplies including storage.

In 2011, NW Natural entered into agreements with Encana Oil and Gas (USA) Inc. to acquire a working interest in proved producing properties and proved undeveloped properties in the Jonah Field in Wyoming. The agreement called for NNW Natural to invest $250 million over five years, as the investment funded new drilling costs in exchange for an ownership interest in wells. The gas production will grow over time and then decline, and is estimated to meet 8-10% of the company's gas requirements for the next ten years, and total savings was estimated at over $50 million over thirty years relative to forward prices at that time. Encana is the operator and is also the majority owner in the field. The utility stakeholders and the commission staff agreed to the acquisition in a stipulation agreement which the Oregon Public Utility Commission approved. In its 2014 Integrated Resource Plan, NW Natural established a target to hedge no more than 25% of its expected annual purchase requirement in the form of long-term hedges.[77]

Washington Gas Light

Washington Gas Light (WGL) announced the acquisition of gas production for $126 million in May 2015. The gas utility acquired working interest in 25 producing wells in Pennsylvania from Energy Corporation America (ECA) who operates over 4600 wells in Appalachia and will be the operator for WGL. The objectives of the acquisition were to reduce gas price volatility impacts and provide expected savings to customers over the twenty year investment period. The transaction is subject to approval by the Virginia State Corporation Commission. WGL pursued the strategy following the 2014 enactment of a new Virginia state law that allows natural gas utilities to recover investment in natural gas assets that provide cost savings, reduce price volatility or reduce supply risk to utility customers. The law enables utilities to acquire up to 25% of supply in the form of gas assets. In addition to allowing the recovery of investment of gas production, the law also allows utilities to build pipelines and other infrastructure in order to bring shale and coalbed methane gas into the state's markets, preferably under long-term arrangements.

[77] NW Natural, *2014 Integrated Resource Plan LC-60 and UG-131473*.

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Questar

In 1981, Questar developed a "Cost of Service" arrangement with natural gas producer Wexpro, where Questar received gas production from wells owned by Wexpro. The contract protects Questar from production risks in that Wexpro assumes all of the risks associated with dry holes o unconnected wells. The original agreement has been expanded to a second agreement which was approved in January 2014 for an additional $103 million investment ("Wexpro II Agreement"). When Wexpro has a property that is within the defined development drilling area, Questar applies to the Utah and Wyoming commissions to include the property in the Wexpro II agreement. If approved, then Questar can earn an allowed rate of return on the investment. At that point Wexpro drills the well and if it is a dry well or non-commercial, Wexpro accepts the risk. Successful gas well production flows to Questar to serve customers. Questar also participates in associated oil production revenues.[78] In its 2014 Annual Report, Questar reported that the Wexpro designs its development program to meet 65% of Questar Gas' weather normalized gas supply needs. The gas is transported by Questar Pipeline and delivered to Questar Gas.

Northwestern Energy

Northwestern Energy (Northwestern) has developed a significant natural gas reserves portfolio, seeing such resource acquisitions as significantly reducing supply cost variability to its gas customers. This strategy was developed and articulated in its 2008 and 2010 Gas Procurement Plans and has been supported by the Montana Public Service Commission (Montana PSC). Northwestern has entered into three major properties as the major leaseholder in Montana for a total investment of $100 million, resulting in 84.6 Bcf of natural gas reserves and associated gathering systems and 82 miles of transmission. The producing properties provide approximately 6 Bcf of production annually. In its 2014 annual report, Northwestern reported gas production currently meets 29% of annual demand and the company intends to add gas production until 50% of its gas supply requirements for gas customers are met with reserves. The 50% target applies to both utility gas customers' load and natural gas fuel demand for two of its electric generating facilities, for a total of 25 Bcf of annual production. In an American Gas Association presentation dated May 2015, the company stated "As we continue to add to our natural gas reserves portfolio, we anticipate a reduction in supply cost volatility for our customers".

[78] Barrie L. McCay Vice President- Regulatory Affairs & Energy Efficiency, Questar Gas Co., *Protecting Customers From Rising Future Gas Prices*, NARUC Western Conference, June 3, 2014.

Southern California Public Power Authority, LADWP and Turlock Irrigation District (Electric) – California.

In 2005 a consortium of public power utilities in California together acquired gas reserves. The group paid $300 million to Anschutz Pinedale Corp. for 38 oil and gas wells on 1,800 acres of the Pinedale Anticline for an expected 112 billion cubic feet of natural gas production over the life of the field. Southern California Public Power Authority (SCPPA)[79] led the acquisition on behalf of Los Angeles Department of Water & Power (LADWP) who acquired 74.5% of the total purchase, Turlock Irrigation District (Turlock), and the cities of Anaheim, Burbank, Colton, Glendale and Pasadena. In its 2005-2006 Annual Report, SCPPA noted "This purchase, along with similar future purchases, will provide a secure source of gas for the participants, and hedge against volatile prices in the market."[80]

In 2006, SCPPA members (Anaheim, Burbank, Colton, and Pasadena)[81] and Turlock purchased additional reserves in the Barnett Shale in Texas of approximately 67 Bcf. SCPPA's Executive Director noted, "For economic, environmental and reliability reasons, SCPPA members have invested heavily in base-load natural gas generation. This acquisition will help ensure the firm delivery of natural gas at stable prices – in a highly volatile natural gas market. This initiative will further enhance the participants' ability to achieve its goal of maintaining stable retail electric rates for their customers." SCPPA also stressed the importance of their partnership with Devon as operator, "As the largest and most active E&P company in the field, SCPPA's participants will benefit from their extensive experience, technical workforce and service-vendor relationships."[82] In its 2012 Annual Report, SCPPA stated an intention to secure "similar future purchases." The Wyoming and Texas properties were acquired from Collins & Young Holdings, L.P and the operator of the properties was Devon Energy Corporation. The gas reserves serve to hedge future natural gas requirements for gas-fired generation.

As of 2014, Turlock Irrigation reported its natural gas supply made up 6% of its net utility plant assets. The proceeds from sale of the gas production is used to off-set the cost of gas purchased to run the District's gas-fired generation. The utility participates in new drilling activity for these properties. Revenue from the sale of natural gas production was $17 million in 2014 and $12 million in 2013.

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[79] Southern California Public Power Authority is a Joint Powers Authority (formed under the Joint Powers Act of the California Legislature in 1980) and has 12 public power agency members.
[80] Southern California Public Power Authority, *2005-2006 Annual Report*, 4.
[81] Southern California Public Power Authority, *2012 Annual Report*.
[82] Southern California Public Power Authority, http://www.scppa.org/Downloads/Press%20Releases/PressRelease2006-10-26.pdf (accessed: December 2013)

In its 2014 Integrated Resource Plan, LADWP reported that the Pinedale reserves cost was $4.24/ MMBtu in 2015, rising to $4.48/ MMBtu by 2029. The volumes LADWP expects to receive are 18,270 MMBtu/day in 2015, decreasing to 10,660 MMBtu/ day by 2029. In addition to its gas production, LADWP employs financial hedges for up to ten years and physical hedges for up to five years. In March 2014, the Department revised its hedging strategy to hedge up to 50% of the gas supply in the current fiscal year, declining by 10% per year thereafter until a minimum level of 10% is hedged.

Sacramento Municipal Utility District

In 2003, the Board of the Sacramento Municipal Utility District (SMUD) approved a purchase agreement of $135 million for SMUD to acquire natural gas reserves from El Paso Production Oil & Gas Co., a unit of El Paso Corp. The gas reserves were located in northern New Mexico and production would be transported to SMUD's gas generating facilities. The gas production was anticipated to meet approximated 15% of the District's long-term natural gas requirements.[83] The transaction was entered into because it was more cost effective than contract market alternatives and provided both reliability benefits as well as a hedge against price volatility.

[83] Sacramento Municipal Utility District, *SMUD Staff Implementation Plan of Board Strategic Directives 2005-2011.*

Appendix B – Detailed Explanation of Forward Price Scenarios

Aether developed a range of price scenarios for the portfolio modeling against which to stress-test the gas supply costs. Eight of the price scenarios were price forecasts developed by third parties [redacted] Three price scenarios were developed additionally: Base Case Price scenario, Illustrative Reserves Price scenario, and Extreme High price scenario. This Appendix describes the sources for the eight price forecasts and the rationale for the additional three scenarios.

All the price scenarios in Aether's model are in nominal dollars. The model used nominal dollar price scenarios since one of the model steps is to convert future gas supply costs into net present value terms. This means that the prices are in in unadjusted dollars, to reflect the then current value. This is in contrast to a price that is adjusted to equivalent dollars for a stated period in time ("real dollars") or prices brought back to present dollars ("net present value").

Price Forecasts

[redacted] so Aether made an adjustment using the same conversion as [redacted] into nominal dollars. This Appendix includes information taken from both [redacted] to provide background about some of the major assumptions behind the forecasts. However, this information refers at times to prices in the forecasts and these are in [redacted] Therefore, they will not be the same as the nominal dollar versions of these forecasts that are shown in Figures 1 and 62.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

84 [redacted]

[redacted]

[redacted]

[redacted]

It is important to note [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[85] [redacted].

[86] Ibid., 7.

[87] Energy Information Administration, *Analysis of the Impacts of the Clean Power Plan*, May 2015, p.24, http://www.eia.gov/analysis/requests/powerplants/cleanplan/pdf/powerplant.pdf (Accessed: June 2015)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[88] See Figure 46 – Clean Power Plan: Change in Generation for AEO2015 Reference Case for additional information of the impact of the Clean Power Plan on generation forecasts.

[89] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

- [redacted]

- [redacted]

[redacted]

Additional Scenarios

To supplement the eight price forecasts, Aether used three other price scenarios: a) Base Case Price scenario b) Illustrative Reserves Price scenario and c) Extreme High Price scenario.

A. Base Case Price Scenario

The Base Case Price scenario is a [redacted] This is a resource planning approach used by BHUC for long-term modeling. Aether used it as well to be consistent.

B. Illustrative Reserves Price Scenario

The Illustrative Resources Price scenario is a theoretical price scenario used by BHUH to assess the potential opportunity associated with acquiring gas reserves. This is a hypothetical price scenario, not directly based on any actual property. For its modeling purposes Aether treated the Illustrative Reserves Price scenarios a Colorado location. The Illustrative Reserves Price scenario reflects the value to a utility of a strategy to drill and produce properties. The price decline illustrates the theoretical efficiencies over time in drilling and production which more than off-set the effects of inflation.

C. Extreme High Price Scenario

Aether included an Extreme High Price scenario, based upon historical price growth. Aether examined the compounded annual growth rate in gas prices in the period of 1998 to 2008, prior to the financial crisis and shale gas technology shift. Aether noted the compounded annual growth rate (“CAGR”)) over the twenty year period of 1988 to 2008 was 8.06%, while the CAGR for the ten year period of 1998 to 2008 was significantly higher at 15.54%. These values are shown in the table below.

Figure 71 – Historical Price Analysis of Compounded Annual Growth 1988-2008 and 1998-2008

Historical Price Analyses (Nominal $)

Year	Average Wellhead Price Data (EIA)	Henry Hub Price Data (Reueters, EIA)
1988	$1.69	NA
1989	$1.69	NA
1990	$1.71	$1.72
1991	$1.64	$1.47
1992	$1.74	$1.77
1993	$2.04	$2.11
1994	$1.85	$1.94
1995	$1.55	$1.68
1996	$2.17	$2.73
1997	$2.32	$2.49
1998	$1.96	$2.09
1999	$2.19	$2.27
2000	$3.68	$4.31
2001	$4.00	$3.96
2002	$2.95	$3.38
2003	$4.88	$5.47
2004	$5.46	$5.89
2005	$7.33	$8.69
2006	$6.39	$6.73
2007	$6.25	$6.97
2008	$7.97	$8.86
2009	$3.67	$3.94
2010	$4.48	$4.37
2011	$3.95	$4.00
2012	$2.66	$2.75
2013	NA	$3.73
2014	NA	$4.39
Price Appreciation 1988 to 2008	472%	
CAGR Avg Wellhead (1988 - 2008)	8.06%	
Price Appreciation 1998 to 2008		424%
CAGR HH 1998-2008		15.54%

The following table illustrates the CAGR for each of the forecasts used in Aether's model. [redacted]

[redacted] But that period included very slow growth in the first decade with far greater growth in the second decade. Therefore, Aether elected to include an Extreme High Price scenario at two times that of the Base Case Price scenario, for this had a CAGR of 9.78%. This is not Aether's price forecast or prediction for the future, but rather a scenario worth considering amongst a range of price scenarios.

Figure 72 – Compounded Annual Growth Rates of Each Price Scenario in the Model

[redacted]

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Appendix C – Glossary of Terms

AGA – American Gas Association.

At the Money – An option with a strike price that is the same as the current forward market price.

Basis – The price differential between the price of a commodity at one location versus the price of the underlying commodity at the primary location.

Basis Risk – The risk that the value of the commodity used as a hedge at one location does not move in line with the underlying exposure of the commodity at the primary location.

Bbl – An abbreviation for "barrel". A unit of measurement for crude oil.

Bcf – A natural gas volumetric measurement representing one billion cubic feet. One billion cubic feet (1 Bcf) is equal to 1,000,000 Mcf.

Bid/Ask – A measure of market liquidity, defined as the difference in price between what a buyer is willing to pay (the bid) and what a seller is willing to sell (the ask).

Break-even – Refers to the price level at which a producer can recover all of its costs.

Brownfield – Re-purposing of an existing site for a different but related technology and use. Typically uses some of the existing infrastructure and requires less permits and authorizations than a new construction project would require.

Call Option (also referred to as a Cap) – Provides the buyer the option, but not the obligation, to buy at a pre-determined strike price.

CFTC – U.S. Commodity Futures Trading Commission, a federal agency with oversight of futures and financial derivatives trading.

Clean Air Interstate Rule (CAIR) – On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). This rule provides states with a solution to the problem of power plant pollution that drifts from one state to another. CAIR covers 27 eastern states and the District of Columbia. The rule uses a cap and trade system to reduce the target pollutants—sulfur dioxide (SO_2) and nitrogen oxides (NO_x)—by 70 percent. CAIR is currently in place while the CF Circuit considers the U.S. Supreme Court's motion to lift the stay of the Cross State Air Pollution Rule.

Clean Power Plan – On August 3, 2015 President Obama and the EPA announced the final to cut emissions from existing power plants. The goal is that by 2030, carbon emission from the power sector will be cut by 32 percent nationwide below 2005 levels.

CNG – Abbreviation for "compressed natural gas". Natural gas is pressurized to less than 1% of the volume it occupies at standard atmospheric pressure.

Collar – An option structure intended to bracket the contract price between a ceiling price and a floor price; a buyer of a collar purchases a call option and sells a put option.

Compounded Annual Growth Rate (CAGR) – A tool to measure the annual growth rate of an investment over a specified period of time longer than one year, when the growth rates are not constant for each interval.

Contango – Used to describe a market occurrence when forward prices are higher than the spot price and escalate into the future.

Correlation – A statistical term describing the relationship between two variables. "Tightly correlated" refers to two variables that move very similarly to one another.

Credit Risk – Financial risk associated with potential default by counterparty.

Cross-State Air Pollution Rule" (CSAPR) – EPA regulation introduced in 2011 after the DC District court vacated the Clean Air Interstate Rule, to address the "Good Neighbor" aspect of the Clean Air Act. The regulation focuses on the transport of air pollution impacting the downwind states ability to comply with National Ambient Air Quality Standards (NAAQS).

Delivery Month – The month in which delivery occurs in connection with a transaction between two parties.

Dodd Frank CFTC Regulation – The Dodd Frank Act was signed into law in 2010 to regulate the financial derivatives market.

DOE – U.S. Department of Energy.

ECA – An abbreviation for "Energy Cost Adjustment", a fuel cost recovery mechanism to allow an electric utility to recover purchased power and fuel.

EIA – Energy Information Administration, a division of the U.S. Department of Energy that provides energy forecasts and statistics.

EUR – Estimated ultimate recoverable is a measure of the estimated total recoverable volume of oil or gas over the life of the well.

Exchange (trading exchange) – A platform upon which buyers and sellers can execute physical and/or financial transactions.

Execution – The act of entering into a purchase or sale transaction with a third party.

Extrinsic Value – Represents the additional value of an option contract over and above the intrinsic value.

FCM – Futures Commission Merchant

FERC – Federal Energy Regulatory Commission.

Financial Derivative – A financial instrument whose value is determined by the price of a commodity market index that typically reflects the price of a physical commodity.

Forward Contract – A Forward Contract is an agreement to buy or sell a commodity for future delivery at predetermined time.

Fundamental Analysis – An analysis of supply and demand factors that will influence the underlying price of a commodity.

Gas Supply Year – November 1- October 31.

Greenfield – New construction, typically requiring full infrastructure investment and permits and authorizations for a new site.

Hedge – To hedge is to offset, mitigate or reduce a risk or risks by entering into a transaction with a third party.

Hydraulic Fracturing – The fracturing of rock by a pressurized liquid to extract crude oil, natural gas and natural gas liquids.

Integrated Resource Plan – A utility plan that estimates the future long-term resource requirements given load projections, energy efficiency projections and available generation capacity.

Intrinsic Value – The value that can be locked in for an option at current market prices.

Liquidity – Assessment of the depth of a commodity market, with respect to the ability to execute transactions with a wide set of counterparties at prevailing market prices.

LNG – An abbreviation for "liquefied natural gas". Natural gas is converted through intense pressure and cold temperature to liquid, for ease of storage or transport. Liquefied natural gas takes up about 1/600th the volume of natural gas at standard atmospheric pressure.

Long Position – The position of a party that has surplus supply and needs to sell prior to the delivery period

Margining – Margining is a form of settlement, whereby counterparties agree that a party will post collateral to the other party when the value of an open transaction or set of transactions exceeds a pre-agreed threshold.

Marked to market – A calculation of the value of positions relative to the current forward market prices.

Market Risk – The risk to the portfolio associated with changes in forward market prices.

Mcf – A natural gas volumetric measurement representing one thousand cubic feet. Typically one Mcf is equal to approximately one MMBtu.

MMBtu – A measurement of energy content representing one million British thermal units. This unit of measurement is typically used as a unit price in wholesale natural gas markets.

Mmt – Million metric ton.

National Ambient Air Quality Standards (NAAQS) – EPA was required in the Clean Air Act to develop air quality standards to protect public health and the environment. There are two sets of standards. Primary standards relate to public health, particularly for sensitive populations (children elderly, asthmatics) and the secondary health standards elate to air visibility and damage to animals, crops and structures.

NEB – National Energy Board in Canada.

Netback – A gas or oil producer's gross margin defined as the sales price minus royalties, production and transportation expenses.

Net Position – The net of all "long" and "short" elements within a portfolio.

Nominal Dollars – Refers to prices quotes in unadjusted dollars, to reflect the then current value. This is in contrast to a price that is adjusted to equivalent dollars for a stated period in time.

Option – An instrument that gives the buyer the right, but not the obligation, to buy, or to sell, a commodity at a specified price at some point in the future.

Optionality – A resource or an asset is described as having "optionality" when it is a flexible resource and that flexibility has market value. If a resource is an option or a series of options, it is sometimes referred to as a "real option".

Out of the money – An option strike price that is higher than the current forward market price (for a call option) or lower than the current forward market price (for a put option).

PCA – An abbreviation for "Power Cost Adjustment", a fuel cost recovery mechanism to allow an electric utility to recover purchased power and fuel. It is usually a mechanism that allocates costs and benefits between customers and the utility.

PGA – Abbreviation for "Purchased Gas Adjustment" mechanism. This is a gas cost recovery mechanism for gas utilities.

Portfolio – The aggregation of all supply and delivery obligations, including load, resources, fuel and third party purchase and sale agreements.

Put Option (also referred to as a Floor) – Provides the buyer the option, but not the obligation, to sell.

Rate Mechanism – A rate structure for a utility's customers.

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Real Dollars – Refers to prices or a data that have been adjusted for an inflation rate.

Return on Equity (ROE) – The amount of net income earned as a percentage of shareholder equity.

Short Position – The position of a party that is deficit supply and needs to purchase prior to the delivery period.

Speculative Trading/Speculation – Speculative trading, also known as proprietary trading, is the deliberate assumption of risk for the purposes of earning trading profits.

Spot Market – The near-term or immediate market for the purchase and sale of a commodity.

Spot Market Price – The price at which purchases and sales are transacted in the spot market; spot market price is often posted in a trade publication.

Stress-test – A test to simulate the effect of an extreme event on a portfolio.

Strike Price – The price at which a physical commodity is delivered or a financial payment is made in connection with a financial instrument, when an option is exercised.

Volatility – A measure of the rate and velocity at which market prices move up and down.

VPP – A Volumetric Production Payment is an arrangement where a seller delivers gas to the buyer in exchange for an up-front payment. The seller conveys a limited volumetric over-riding royalty interest (i.e., a non-operating interest) in producing fields to the buyer as collateral.

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Appendix D – Document Review and Company Interviews

Figure 73 – Document Review

Long-term Hedging Program Elements	Document Review
Gas Supply Plan and Hedging	▪ Gas Supply Plans ▪ Gas Supply Services Risk Policies and Procedures ▪ Hedging program plan documents ▪ Black Hills 2014 10K and Annual Report
Load and Resources	▪ Long-term natural gas demand projections for natural gas customer load and natural gas fuel for power plants [redacted]
Gas "Cost of Service" Strategy	▪ External presentations to investor community ▪ Presentations to Commission Staff

Aether met with the following Black Hills representatives to conduct internal interviews:

- Vice President, Operations Services
- Vice President, Energy Asset Optimization
- Director, Gas Supply Services
- Sr. Manager, Gas Supply (Planning & Forecasting)
- Manager, Financial Modeling

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Figure 74 – Illustrative Interview Questions

Hedging Program Elements	Sample Interview Questions
Gas Supply Portfolio	▪ Please describe your aggregated gas supply portfolio, highlighting major sources of demand and supply. ▪ How do you use gas storage and where is it located? ▪ What volumes of gas do you purchase and at what market locations? ▪ How is your gas demand for power generation changing over time? ▪ Please describe seasonal load variability in your portfolio. ▪ How is your average day gas portfolio changing over time? ▪ What are your planning criteria regarding additional gas requirements? ▪ Does your forecast assume any changes in gas storage?
Risk Exposure	▪ What are the most significant natural gas risks in your portfolio today? ▪ What risk reporting do you have?
Hedging Program Goals	▪ What are the hedging goals of your gas hedging program? ▪ Please describe the current hedging program. How long have you used this approach? ▪ What elements of your hedging program are programmatic and which are more discretionary? ▪ Who reviews and approves the hedging program plan? ▪ Is the hedging plan similar for gas for gas customers and for fuel for the gas generating plants? Where might they differ? ▪ What hedging instruments do you use today? What others have you considered using? ▪ Please describe the tenor (time horizon) of your hedging plan and how far forward hedges are executed.

Hedging Program Elements	Sample Interview Questions
	▪ How is hedging success measured internally and by your stakeholders? ▪ What instruments do you use to hedge? ▪ Do you have adequate number of counterparties for your current hedging? ▪ Are there volumetric or liquidity constraints hedging in medium and long-term markets? Are there only certain instruments you could execute or certain markets where you could transact? ▪ How do you monitor the hedging plan? ▪ What are BHUH's annual hedging targets? ▪ What decisional criteria do you use to hedge?
Long-Term Hedging	▪ What are the most liquid instrument and markets for hedging and how far forward can you hedge? ▪ What long-term hedging products are available to you? ▪ Are there counterparties that you can transact with for long-term hedges? ▪ What expertise does your organization have in natural gas reserves? ▪ Please describe the Cost of Service Gas proposal. ▪ What type of reserve investment are you considering? ▪ Please describe the Hedge Credit/ Hedge Cost mechanism.

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Appendix E – Consultants' Resumes

JULIA M. RYAN (PROJECT MANAGER)

jryan@aetheradvisors.com

Energy industry executive with proven leadership skills and record of achievement in risk management and strategic planning. Experienced in project management, portfolio analysis, business start-ups, M&A initiatives, trading & origination. Collaborative leader, providing strategic vision to power and natural gas companies as well as insight to complex risk management issues.

PROFESSIONAL EXPERIENCE

AETHER ADVISORS LLC
Seattle, Washington — 2012-Present, 2006-2011

Managing Partner
Established Aether Advisors LLC to provide advisory services to senior executives of regulated and non-regulated energy companies. Provided hedging advice and conducted risk management reviews for utilities. Developed strategy for utility, merchant power, competitive retail marketer, and energy trading clients. Provided investment advice and due diligence services to private equity and merchant power clients.

CONCENTRIC ENERGY ADVISORS INC.
Seattle, Washington — 2011-2012

Vice President
Led the firm's Risk Management practice and was responsible for business development and the delivery of advisory services to clients. Reviewed the tools, techniques, and decisional documentation of utilities' risk management programs. Reported to President.

PUGET SOUND ENERGY
Bellevue, Washington — 2001-2006

Vice President, Risk Management and Strategic Planning (8/2005-2/2006)
Directed "Risk Operations", consisting of Corporate Budgeting, Credit Risk Management, Energy Risk Control, and Internal Audit. Managed 25 professional staff. Implemented Company's enterprise risk management framework. Executive member of the following oversight committees: Disclosure Practices, Risk Management, Sox 404, Ethics and Compliance, Energy Resources, Emissions Marketing, and Financial Outlook. Reported to CFO.

Vice President, Energy Portfolio Management (12/2001- 8/2005)
Managed the utility gas portfolio as well as the utility electric portfolio (hydro, coal generation, gas-fired generation, and market purchases). Led 35-40 professionals in risk management, quantitative analysis, financial analysis, and trading. Reported to CFO.

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TRANSALTA USA (FORMERLY MERCHANT ENERGY GROUP OF THE AMERICAS)
Annapolis, MD 1997- 2001

Managing Director, North American Marketing (formerly Managing Director, Origination)
One of the four principals who developed a North American marketing, trading and merchant power business plan and entry strategy for parent companies, Gener S.A. and TransAlta. Reported to CEO of Merchant Energy Group, and later to TransAlta CFO.

LOUIS DREYFUS CORPORATION
Wilton and Stamford CT, Winnipeg MB, and Kansas City KS 1984-1997

Senior Vice President, Duke/Louis Dreyfus L.L.C., Wilton, CT (2/96-6/97)
Conceptualized business plan for joint venture marketing alliances, national accounts and regional accounts. The products and services developed included derivatives products, energy management outsourcing, supply portfolio hedging, tariff analysis and fuel consumption analysis. Reported to Executive Vice President.

Vice President, Louis Dreyfus Corporation, Wilton, CT (4/89-1/96)
Established the Company's natural gas trading and marketing division in 1989. Largest profit area was linked to long-term sales, hedged with futures and natural gas producing properties. Reported to President.

Merchant, Louis Dreyfus Corporation, Kansas City KS, Winnipeg MB, Stamford CT (6/84-3/89)
Diverse trading career in domestic and international agricultural commodity markets.

EXTERNAL

- Appointed to Seattle City Light Review Panel (2010- current)
- Guest instructor at the Atkinson Graduate School of Management, Willamette University. Currently co-director for the "Utility Management Certificate Program" (2006 – current).
- Guest speaker at industry conferences on risk management (2006- current)
- Authored articles on utility hedging and risk management for Public Utilities Fortnightly (2012) and Wiley Periodicals (2009-2010)
- Board member of the Northwest Gas Association (2002-2006)
- Extensive presentation experience with Company boards, state regulators, major customers and elected officials

EDUCATION

SMITH COLLEGE, Northampton, MA
B.A. English, 1984 Smith College, Northampton, MA.
Cum Laude and Phi Beta Kappa

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CHRISTOPHER ATHAIDE

cathaide@cygnetriskgroup.com

PROFESSIONAL EXPERIENCE

CYGNET RISK GROUP, LTD.
Houston, TX
2000 – Present

Cofounder and Partner

- Consulting Services: Consultant to several energy firms on different aspects of energy risk.
  Projects include: Completion of utility gas hedging strategy model
  Development of Forward Curves for Power Modeling Valuation of a Tolling Power Plant.
  Development of Optimization Algorithm for Power Plant Scheduling.
  Development of methodologies for evaluating credit risk of counterparties.
  Development of artificial intelligence algorithms for predicting power price spikes.

- Products: Author/Developer of the CRG Natural Gas Storage Model. This is the most sophisticated tool currently on the market for pricing and hedging the value of natural gas storage facilities. This model is currently used by several companies to value and trade their natural Gas Storage.

SHELL GAS TRADING
Houston, TX
1997-2000

Director, Asset Management and Storage

- Storage and Asset Management: Values and traded complex multi-year deals with multiple assets including gas storage and transportation. Developed a number of models to value such deals.
- Worked on the options desk and the gas physical desk. Priced several complicated options including weather options, first-of-month options, full requirements deals, tolling options, transport deals, storage valuation and other power/gas cross-commodity deals.
- Worked with earlier versions of Endur (Abacus) to assist with the setup.
- Worked on models to predict the EIA weekly storage number, risk of the trading desk and implementing value-at-risk.

J.P. MORGAN
New York, NY
1992-1997

Vice President, Global Markets

- Member of the group that developed RiskMetrics™ and CreditMetrics™.
- Provided risk management services to banks, government agencies and financial companies.
- Traded and marketed cash and derivative instruments including mortgage backed securities, swaps, options and mortgage swaps.
- Developed analytics for fixed income and derivative trading groups.

MASSACHUSETTS INSTITUTE OF TECHNOLOGY
Cambridge, MA
1992

Instructor, MIT Sloan School of Management

- Taught a course, *Introduction to Management Science*, to undergraduate majors.

EDUCATION

ASSOCIATION FOR INVESTMENT & MANAGEMENT RESEARCH,
Charlottesville, VA
Chartered Financial Analyst

- Awarded the CFA charter from AIMR in 1998.

MASSACHUSETTS INSTITUTE OF TECHNOLOGY, Cambridge, MA
Doctor of Philosophy in Operations Research 1987- 1992
Courses include stochastic calculus, options theory, corporate finance, financial economics, accounting, linear/nonlinear/dynamic programming and probability theory.

RENNSELAER POLYTECHNIC INSTITUTE, Troy, NY
Master of Science in Operations Research and Statistics, 1985-1987
Courses include probability theory, theory of statistics, experimental design and nonparametric statistics.

INDIAN INSTITUTE OF TECHNOLOGY, Mumbai, India
Bachelor of Technology in Mechanical Engineering, 1981-1985

Computer/Systems

Systems: OLF Endur – Business/Risk Analyst.
Programming Languages: Proficiency in the .NET platform, VB.NET, C#, F#, C++, LINQ, SQL, Excel, and AVS. Author of the CRG Natural Gas Storage Model in C#.