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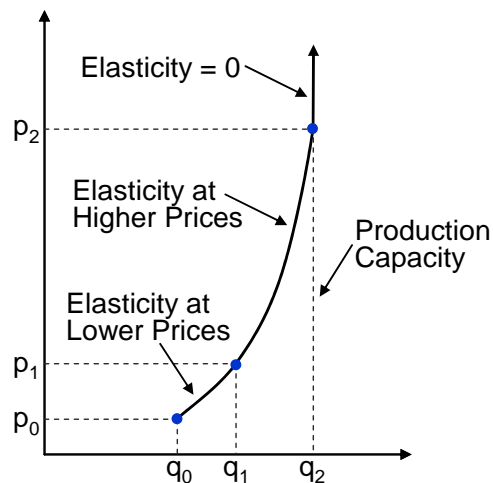
## APPENDIX 1

### GPCM MODEL THEORY AND STRUCTURE

LAI's modeling approach is based on the microeconomic principles underlying the theory of competitive markets. In competitive markets – no barriers to entry and exit, lots of buyers and sellers – price is determined by the interaction of supply and demand. In RBAC Inc.'s GPCM, supply is assumed to be a non-decreasing function of price and demand is assumed to be a non-increasing function of price. The price at which an increment of natural gas supply is equal to the increment of gas demand defines the market-clearing price and quantity. Each supply source has a specifically defined supply curve. Each customer has a specifically defined demand curve. The model integrates supply sources, customer demands and both pipeline and storage infrastructure. The amount of gas that flows from supply sources through the pipeline and storage network to the market is determined by price differentials. Gas flows whenever the price differential between any two connected market points exceeds the unit cost between such points.

GPCM supply curves relate the amount of gas produced to the price: the higher the price the more gas that will be produced subject to resource and reservoir limitations. As shown in Figure A1-1, the slope of the supply curve determines price elasticity, *i.e.*, the % change in gas supply that can be obtained for a small % change in price. GPCM supply curves are made up of segments that exhibit high elasticity at lower prices, low elasticity at higher prices and at some point zero elasticity where resource and production limits mean that no additional supply can be obtained regardless of price. Higher elasticity indicates that a small change in price brings about a significant increase in supply, and vice versa. This normally happens close to the lower end of the supply curve where significant changes in production can occur due to shutting in wells in response to price drops or through the resumption of production as price increases. The magnitude of the elasticity is lower further up the supply curve as production for the supply area or producing field approaches capacity.

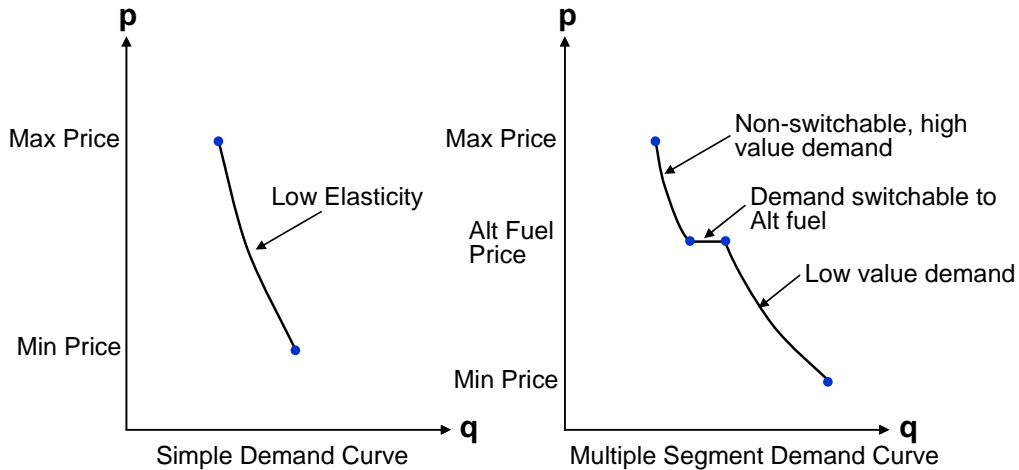
Figure A1-1 – GPCM Supply Curves<sup>1</sup>



<sup>1</sup> Source: RBAC Inc., 2005.

The demand curve sets the relationship between the price and the amount of gas associated with a customer's preference. As prices increase, gas demand decreases. As shown in Figure A1-2, GPCM uses a multi-segment demand curve as fuel substitution effects allow certain price elastic customers to switch to an alternate fuel.

**Figure A1-2 – GPCM Demand Curves<sup>2</sup>**

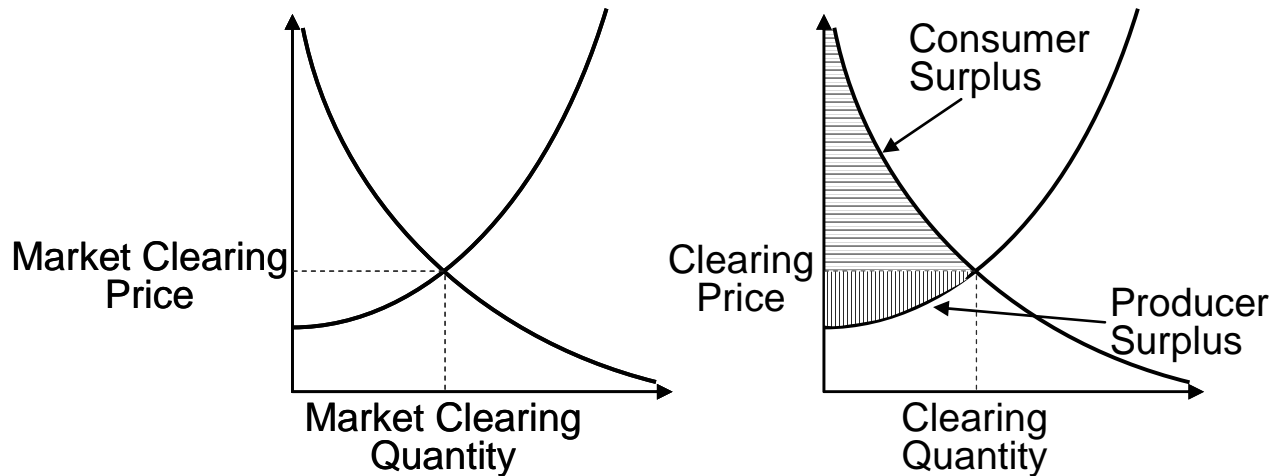


Solutions derived by GPCM require multiple iterations in order to balance supply and demand. Of course, the iterative nature of the solution is not pictured in Figure A1-3, but the calculation of market-clearing prices and quantities, which is equivalent to maximization of the sum of “producer surplus” and “consumer surplus”, requires computation of numerous possible solutions before the optimal solution is found. The model identifies and calculates the flows from supply points to demand points starting with the path with the greatest price differential. Lower cost gas flows are exhausted before higher cost flows between relevant nodes are accepted into the equilibrium solution. Supply and demand are therefore in balance at every node across the continental network. Both price and quantity for a local market equilibrium are influenced by market conditions across the continent. Hence, the level of supply from each supply region and the demand in other consumption regions enter into the determination of the market clearing prices.

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<sup>2</sup> Ibid.

Figure A1-3 – GPCM Market Clearing Price<sup>3</sup>



Many gas industry market participants use GPCM to estimate the impact of new infrastructure on commodity prices, basis differentials and flows on rival transportation paths linking supply regions with consumption regions. Across North America, GPCM model structure is comprised of 86 supply areas, 164 pipelines, 146 storage areas, and 534 demand centers. Hence, results using the optimization framework in GPCM capture exploration and production, pipeline transportation costs, losses, storage injection and withdrawal profiles, pipeline and LNG import terminal additions, and demand. Model solutions constitute the least cost supply for an exogenous demand that “stacks” the flow of natural gas across rival pipeline paths to market centers from least cost to highest cost. Other key factor inputs to GPCM include: pipeline and storage prices (tariffs), supply curves by production basin, LNG terminal storage and daily vaporization capacities, and demand curves by sector and consumption area.<sup>4</sup>

As discussed, solutions incorporate price elasticities. Hence, the economic value of the equilibrium solution reflects both supply and demand elasticities in response to changes in price. The objective function that drives the solution constitutes the “greatest value” solution to serve total demand. Therefore the first-best economic solution reflects the least costly supply flowing first before more expensive supply is selected to meet customer demand. Similarly, customers willing to pay more are more likely to be served than those willing to pay less. Various constraints are incorporated in the model reflecting resource limitations, physical constraints on the pipeline network, and pipeline and storage tariffs. After specifying the applicable constraints for the gas system being modeled, a solution can be generated. In order to find an optimal economic solution to this network-flow problem, the model utilizes EMNET, an advanced LP optimizer.<sup>5</sup> The model is simulated on a monthly basis, thus enabling the development of long-

<sup>3</sup> Source: RBAC, Inc.

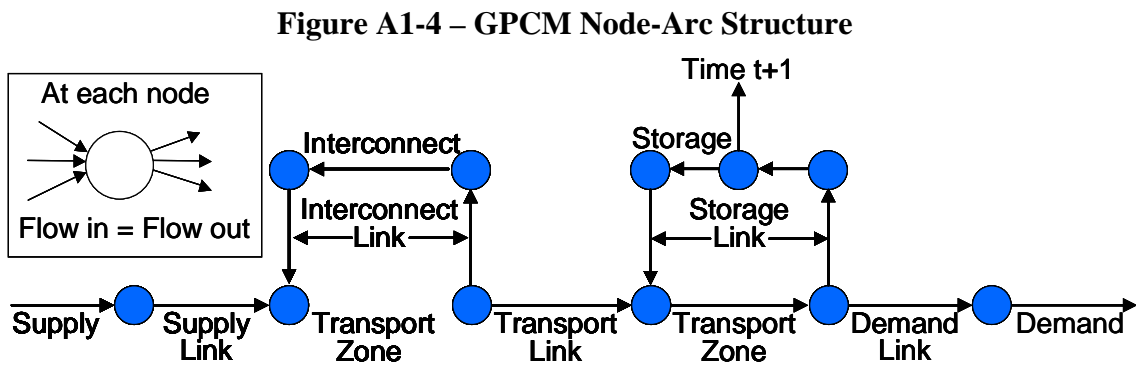
<sup>4</sup> Gas demand for industrials and electricity generators behind the citygate are rolled-up with direct deliveries off the pipe rather than designated separately.

<sup>5</sup> EMNET was developed by Professor Richard McBride at the University of Southern California Graduate School of Business. The EMNET algorithm was designed specifically to solve network flow problems with additional non-

term price forecasts as well as the analysis of seasonal supply/demand effects at primary market pricing points.

The LP framework utilizes a “node-arc” network. Nodes represent production regions and supply basins, pipeline zones, interconnects, storage facilities, delivery points, and either specific large customers or groups of smaller customers. Arcs represent gas transactions and flows. Each arc is constrained by capacity limitations. The many compressors, delivery meters, and receipt meters are conveniently rolled up into “pipeline zones.” Arcs connect the pipeline zones to form the North American pipeline network. Each market, storage facility, supply source and pipeline interconnection that is represented by a node is linked to the corresponding pipeline zone(s) by one or more arcs.

Figure A1-4 provides a generalized schematic for the GPCM node-arc structure.



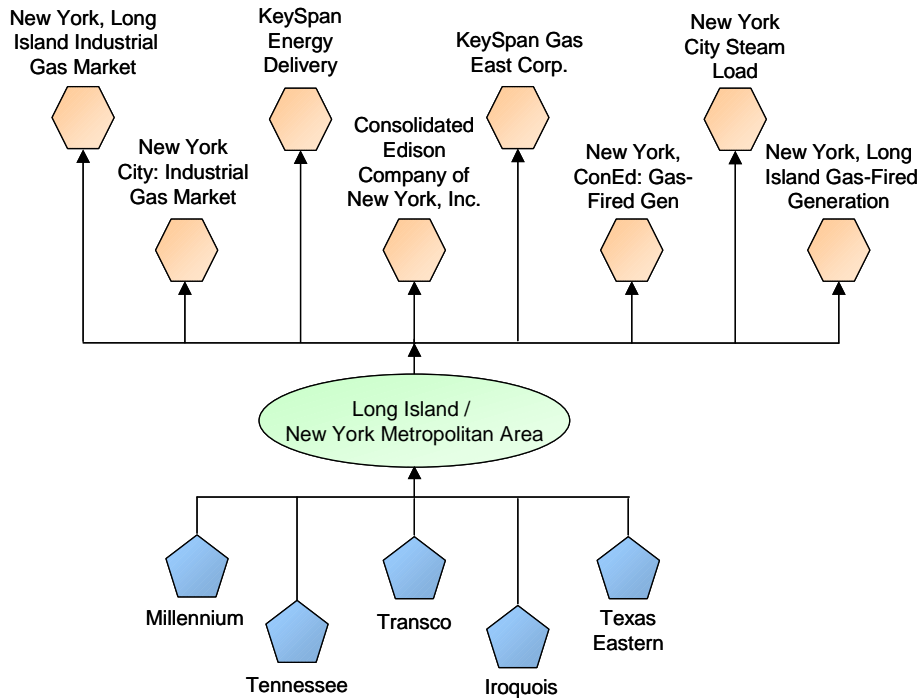
Each arc is defined by a number of parameters including the capacity or maximum flow that can occur at the arc, any required minimum flow for the arc, the costs for the arc, and an efficiency for the arc, to account for compressor fuel and losses. Each supply, demand or transshipment node is treated as a potential market point where supply and demand must be balanced. The amount of gas that moves from supply nodes to transshipment nodes and then on to demand nodes is driven by price differentials. If the price differential between any connected nodes exceeds the unit cost, including fuel and losses, then the EMNET optimizer ensures the orderly flow of natural gas between these nodes. If the price differential between connected nodes is less than the unit cost, then the optimizer hunts for more price efficient flows realizable elsewhere across the supply chain.

Figure A1-5 reflects the model structure for Long Island and New York City across the New York Facilities System.

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network variables and constraints, and has been extended to handle the linearized approximations of non-linear supply, demand and transportation cost functions utilized in GPCM.

**Figure A1-5 – Model Structure for Long Island and New York City**



The supply and demand markets are modeled separately and then connected with a model of the pipeline grid. The gas supply sources modeled in GPCM encompass all of the supply basins and LNG import terminals in North America. Every supply source is constrained by a maximum and minimum daily flow quantity. Hence, every supply source is associated with a supply curve that dictates the amount of gas to be supplied at a given netback price. For each supply source, prices on the supply curve tend to increase over time reflecting higher finding and production costs. However, gas prices have some correlation with crude oil price. Thus assumptions about future oil prices also contribute to the forecast gas price in each production area. Key parameters including the reserves to production ratio and reserves recovery ratio limit supply source production levels. These parameters reflect the relevant depletion trend by producing basin.

All major interstate, intrastate and inter-provincial pipelines are included in the model. Pipeline zones form the basic building block for the model of each pipeline. Long-haul pipelines – even those with postage stamp rates – are differentiated by zones, thus enabling flows between contiguous market areas to be defined, capacity constraints to be identified, and price differentials within relevant boundaries to be captured. Storage injection and withdrawal cycles are incorporated. Each pipeline’s tariff provides the basis for estimating the minimum and maximum transportation prices, as well as relevant fuel retention rates by location, *i.e.*, shrinkage. Price differentials between market points are related to the level of transportation demand between points as well as the overall level of gas prices. This relationship is modeled by assigning a minimum and a maximum price for flow across each zone plus a fractional loss of flow to account for fuel use and losses. Hence, the optimization of flows is achieved with respect to supply and demand based on the cost of transportation between relevant points. A clearinghouse for pipeline transportation is prioritized in accord with character of service: all firm transportation is cleared first before any non-firm transportation is cleared in zonal markets.

The clearing or scheduling of non-firm transportation is performed under volumetric rates that range from a high equal to the 100% equivalent load factor rate, including transport commodity plus shrinkage, to a low equal to a pipeline's firm transport commodity charge.<sup>6</sup>

Storage is modeled as three distinguishable transaction components: injection, storage and withdrawal.<sup>7</sup> Storage facilities are constrained by total storage capacity and daily injection / withdrawal capacity. Storage activity is shaped by a monthly schedule with a constant unit cost per period. The ability to model individual storage facilities on a monthly basis including consideration of inventory balances, withdrawal and injection rates, and facility constraints on injection, withdrawal and inventory allows LAI to introduce demand ratchets at traditional underground storage fields. LAI has incorporated storage ratchets at certain storage hubs of relevance to New York in order to ensure that there is enough working gas storage inventory in February and March. Storage transactions can be modeled where gas is transported to a storage facility on one rate schedule, injected and withdrawn under another and delivered under a third rate. Storage transactions have also been modeled as a bundled structure with all components covered under a single rate.

Major gas customers have been classified as follows: LDCs, industrial, and electric generation. LDC customers therefore represent core demand behind the citygate, including all residential and commercial customers. Non-core includes primarily electric generation and large industrials. Demand curves are delineated for each customer – these represent the amount of gas that would be purchased at a given price. Seasonality is taken into consideration based on the monthly periodicity of the model. Within each market area represented in the model, each demand sector has an individual seasonal profile.

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<sup>6</sup> The firm transport commodity rate represents the usual minimum rate for non-firm transportation that FERC allows a transporter to charge for interruptible service.

<sup>7</sup> Source: RBAC, Inc.

## APPENDIX 2

### BASIN PRODUCTION CURVES

#### Permian Basin

The Permian Basin located mostly in west Texas and southeastern New Mexico is a mature basin that has been a major contributor to U.S. production for many years.<sup>1</sup> The Permian Basin has historically been the primary source of natural gas for California, Texas and the north Central U.S.<sup>2</sup> Recent exploration of deep formations in the Permian Basin may partially offset the production decline. Also, the potential extension of the Barnett Shale may offer new production. LAI expects the Permian Basin to undergo a gradual, but continuing decline in gas production over the forecast period. Permian Basin production has been relatively flat since 1990, with current production at approximately 4 Bcf/d. This basin has traditionally been known for oil production – it still accounts for up to 20% of total U.S. oil production. Associated gas production accounts for 30%-40% of the total production in the basin.<sup>3</sup> This has contributed to historical production stability. While the basin is mature, substantial production from enhanced oil recovery projects will continue to provide associated gas. Moreover, continued activity involving horizontal drilling and down-spacing of the gas wells will help support production. Tight gas formation account for about 30% of production, mostly from the Canyon Formation. Production is expected to decline to around 3.3 Bcf/d by 2020.

Following our analysis and review of historical production trends and reserve additions in the basin, we adjusted the average overall annual basin production decline rate upward to 1% from the 0.5% rate originally included in the GPCM database. The overall basin decline rate reflects the projected trend for all production the basin including production from new wells. In recent years, the decline rate from existing wells, assuming no new wells were drilled has averaged about 16%.

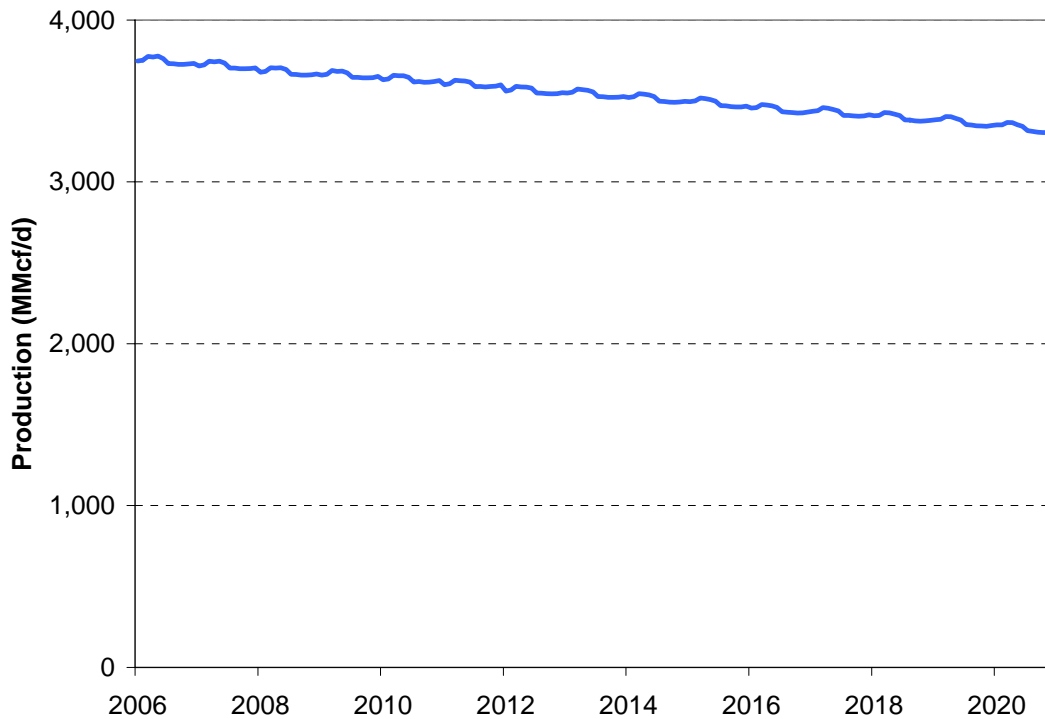
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<sup>1</sup> For this analysis and GPCM modeling, the Permian Basin includes production from eastern New Mexico and Texas Railroad Commission Districts 7B, 7C, 8, and 8A.

<sup>2</sup> Gas supplies from the Rocky Mountains and San Juan basins have largely supplanted Permian supplies in California.

<sup>3</sup> Associated gas is gas that is produced along with oil production as opposed to non-associated gas that is produced from wells without oil production.

**Figure A2-1 – Permian Basin Production**



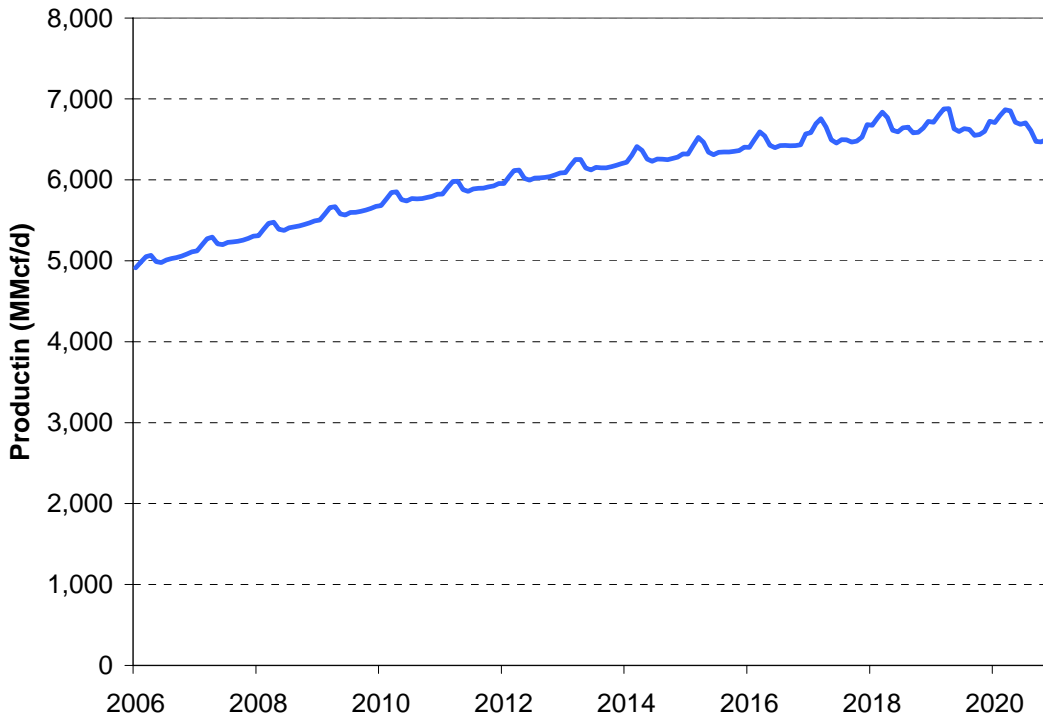
### **Arkla-East Texas Supply Region**

The Arkla-East Texas supply region is a mix of older producing fields along with some of the hottest current exploration plays in North America. This supply region includes fields in Arkansas, northern Louisiana and northeastern Texas with current production of 4.9 Bcf/d.<sup>4</sup> This supply region includes all or parts of some of the fastest growing new gas supply sources such as the Barnett Shale as well as the Bossier Trend and the Cotton Valley Formation tight sands. Currently, wells in Arkla-East Texas are producing more than 3 Bcf/d from a resource base that is estimated to be 95 Tcf.<sup>5</sup> Production from these unconventional gas plays is expected to significantly increase. Growing production from these new fields will more than offset the decline in production from the more mature producing fields with total production in the region reaching 6.7 Bcf/d by 2020.

<sup>4</sup> Texas Railroad Commission Districts 5 and 6.

<sup>5</sup> Ted McCallister, EIA, “Unconventional Gas: Challenges, Successes, and Future Outlook, Unconventional Gas Production Projections in the Annual Energy Outlook 2005: An Overview.” EIA Midterm Energy Outlook and Modeling Conference, April 12, 2005.

**Figure A2-2 – Arkla-East Texas Production**



**Gulf of Mexico**

The Gulf of Mexico includes two producing regions that are experiencing production and depletion trends in opposite directions. The shallow waters of the Gulf are rapidly depleting. Production in the Deep Gulf constitutes a bright spot for U.S. production. Gas production from the offshore fields in the Gulf of Mexico has historically been focused on the relatively shallow waters (200 meters or less) of the continental shelf at total well depths from the seafloor up to 15,000 feet. Production in the shallow Gulf – currently around 8 Bcf/d – has declined steadily since 1990 when production topped out at 14 Bcf/d. This decline is expected to continue over the forecast period. The decline in production has occurred primarily as the result of depletion. The depletion trend has been accelerated by improved well completion techniques. LAI adjusted the initial offshore shelf production in GPCM upward by approximately 1 Bcf/d based on our analysis of historical production trends. The production decline rate was not significantly changed.

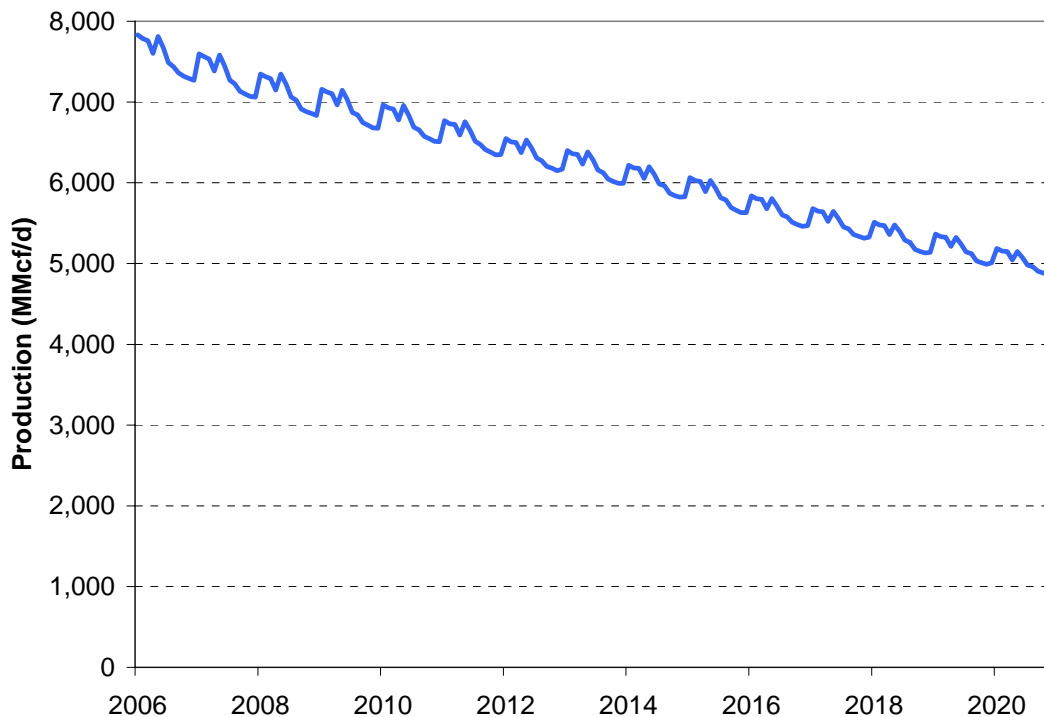
New production in the Gulf of Mexico is likely to be from producing horizons in the deep deposits of the continental shelf (shallow Gulf), often referred to as the Deep Shelf, typically located below the thick tabular salt deposits that cover almost 60% of the northern Gulf of Mexico and in deepwater fields on the Outer Continental Shelf. These areas have been the focus of considerable exploration and development activities in recent years. New exploration targets in ultra deepwater are 18,000 to 30,000 feet below the seafloor in water depths up to 10,000 feet. The deepwater Lower Tertiary formations that stretch from Alaminos Canyon in the western Gulf to Walker Ridge in the eastern Gulf are located in water depths greater than 7,500 feet. This formation has received considerable attention in light of recent new discoveries. Wells being drilled in the shallow waters of the Gulf probing the Deep Shelf deposits have also provided

optimistic indications regarding potential production. While the deepwater gas potential in the Lower Tertiary play is very high, these formations are expected to contain even more oil. Thus, until recently, the deepwater Gulf has been primarily an oil production province with production from gas discoveries made feasible as the result of infrastructure focused on the exploration and production of oil. During the last few years, gas prices have reached high enough levels possibly to rationalize development in ultra deepwater.

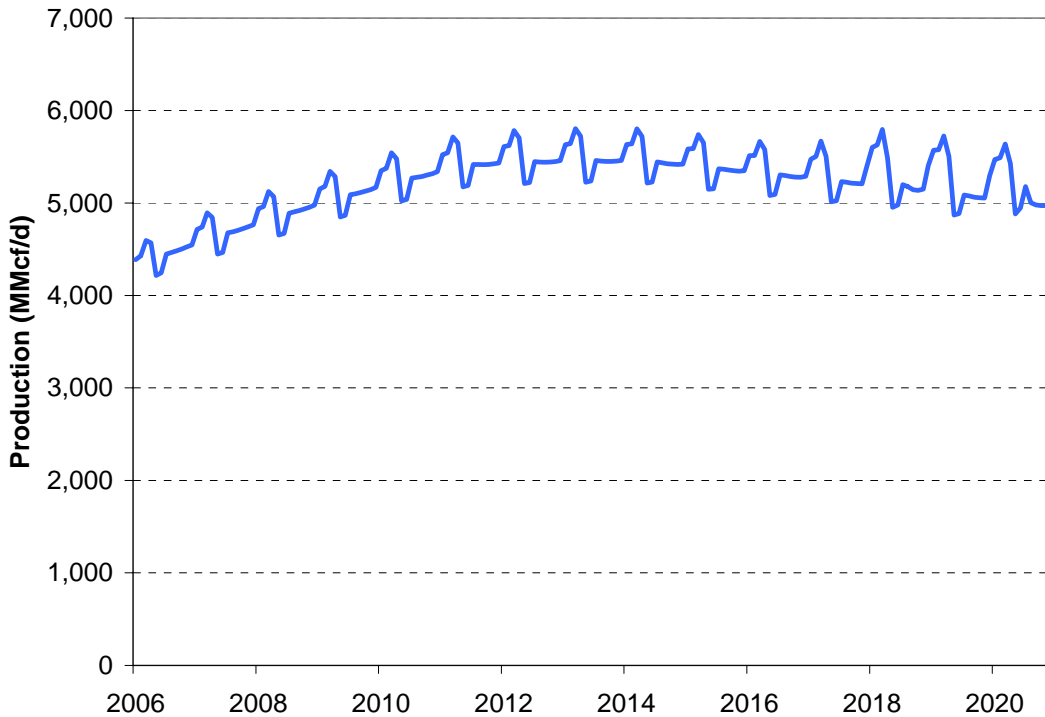
While there is good potential to increase gas production in the deepwater and Deep Shelf formations, the exploration and production facilities needed to deliver these resources will require large capital-intensive offshore production systems for deepwater deposits and high costs to drill wells to geologic depths below 20,000 feet. Development of these resources will also require long lead times to bring new fields into production. The higher costs mean that the current relatively low cost shallow water fields that are depleted will be replaced by higher cost production. This pattern of replacement will likely sustain upward price pressure on commodity prices into-the-pipe at the Henry Hub.

In recent years gas production from deepwater facilities has been ramping up following the development of the necessary production, gas processing and transportation infrastructure. As a result deepwater Gulf production, which was 0.5 Bcf/d in 1992, has increased to 2.9 Bcf/d. This growth is expected to continue over the forecast period with production reaching more than 5 Bcf/d by 2020.

**Figure A2-3 – Gulf Shallow Offshore Production**



**Figure A2-4 – Deep Gulf Offshore Production**



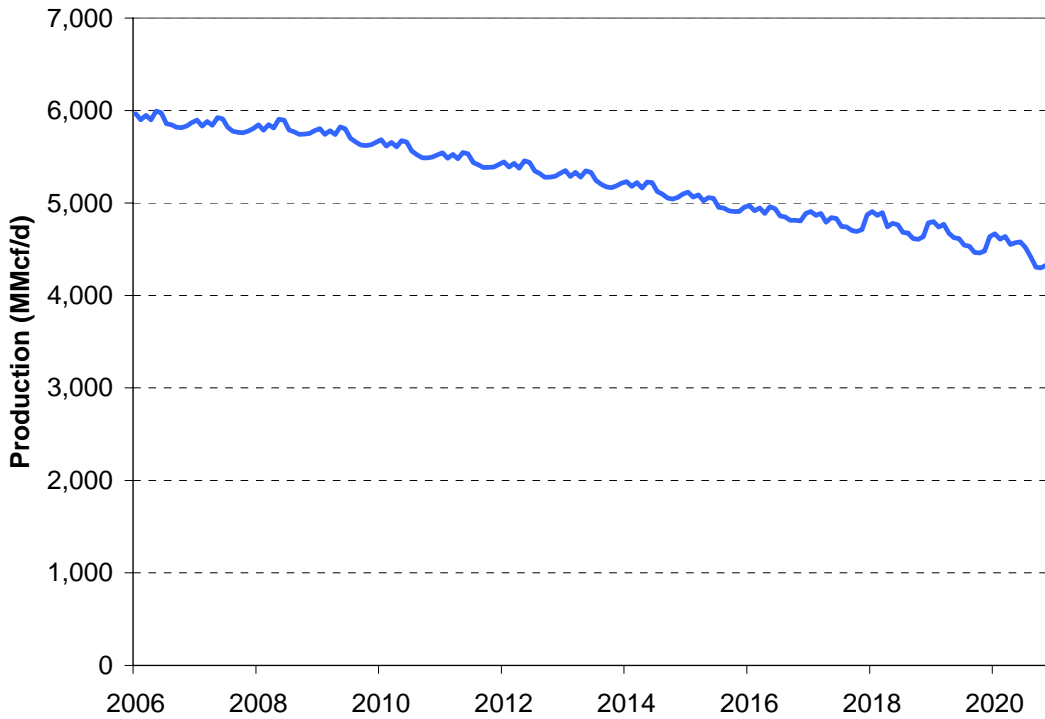
### **Gulf of Mexico Onshore**

The existing onshore Gulf Coast supply region remains one of the largest gas producing areas in the U.S., with current production at more than 9 Bcf/d. This supply region includes fields in the Texas Gulf Onshore region<sup>6</sup> South Louisiana and the East Gulf Onshore region (southern Alabama and Mississippi). Production has been reduced significantly by the depletion of mature fields, particularly in southern Louisiana and southeast Texas.

Production from the Texas Gulf Onshore region was declining in the early 1990s. However, during the mid-1990s production temporarily stopped its decline due in large part to expanded use of 3-D seismic surveys, which helped identify new exploratory targets to be drilled in deeper formations, coupled with improved fracturing and drilling that permitted the development of reservoirs these formations, in particular the Vicksburg, Frio and Wilcox formations. While success rates in this region are buoyed by 3-D seismic, the depletion rates are also high. Starting in 2001, production in the region resumed its decline. New production from recent developments in these formations will help maintain regional production, but with the depletion rates at mature conventional fields overtaking the gain in production from new fields, overall production is expected to decline from 6.3 Bcf/d in 2004 to 4.5 Bcf/d in 2020.

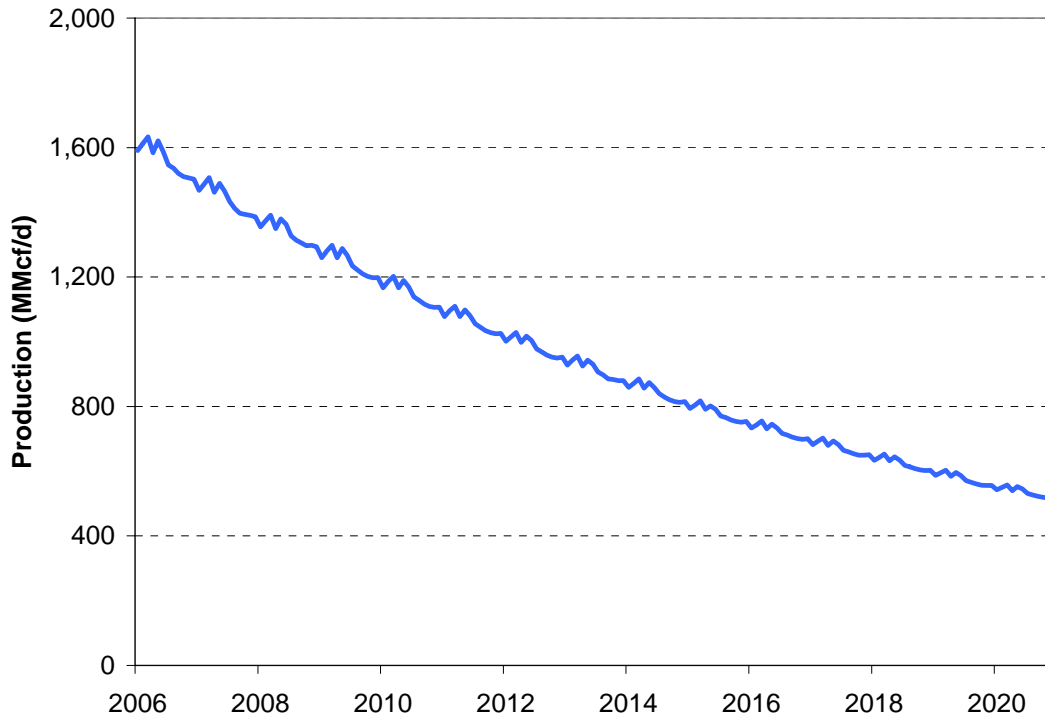
<sup>6</sup> Texas Railroad Commission Districts 1, 2, 3, and 4.

**Figure A2-5 – Texas Gulf Onshore Production**



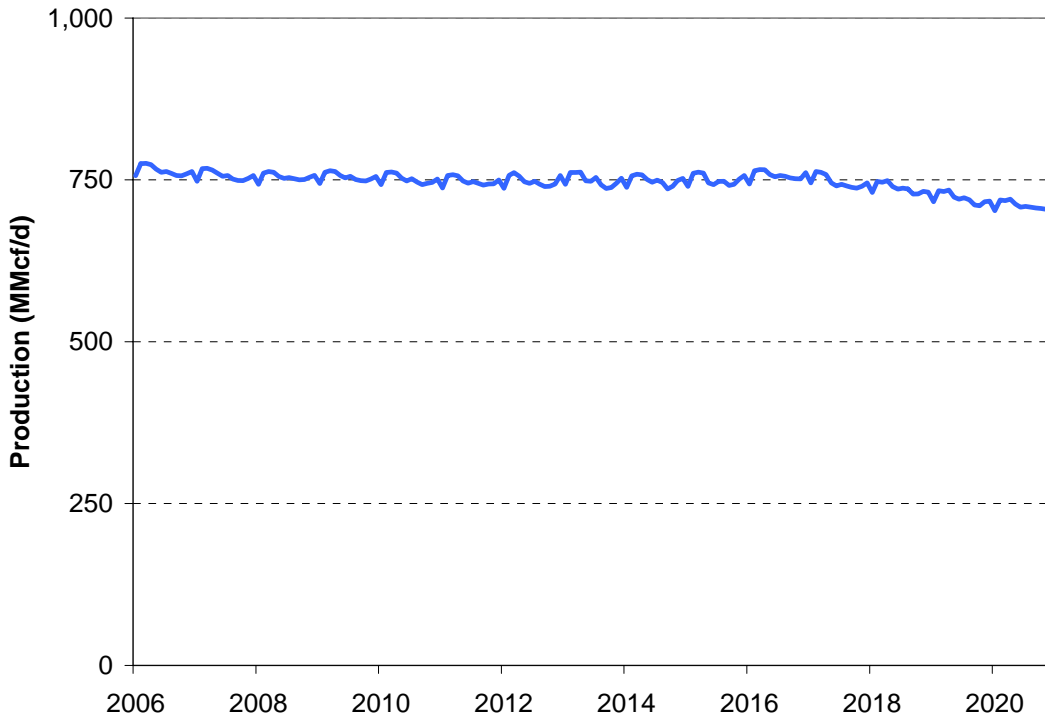
Production from onshore South Louisiana has been declining steadily since the early 1990s, reaching a current level around 2.1 Bcf/d. This represents a 20% drop in production since 1996. During this period, proved reserves in South Louisiana declined by almost 35%. The impact of declining reserves will increase over time. By 2020 production is expected to drop to less than 600 MMcf/d, a victim of aggressive production utilizing new technology and falling reserves.

**Figure A2-6 – South Louisiana Onshore Production**



Production from the East Gulf Onshore gas fields, which are located in Mississippi and southern Alabama, has declined 18% since 1996 and is currently about 800 MMcf/d. Most of this production originates in the Norphlet sandstones from the state waters of Mobile Bay. There have been no new major discoveries in this play since 1995, although there are some indications that it could trend into Florida state waters where oil and gas drilling is generally prohibited. Production over the forecast period is projected to decline to around 700 MMcf/d by 2020.

**Figure A2-7 – East Gulf Onshore Production**



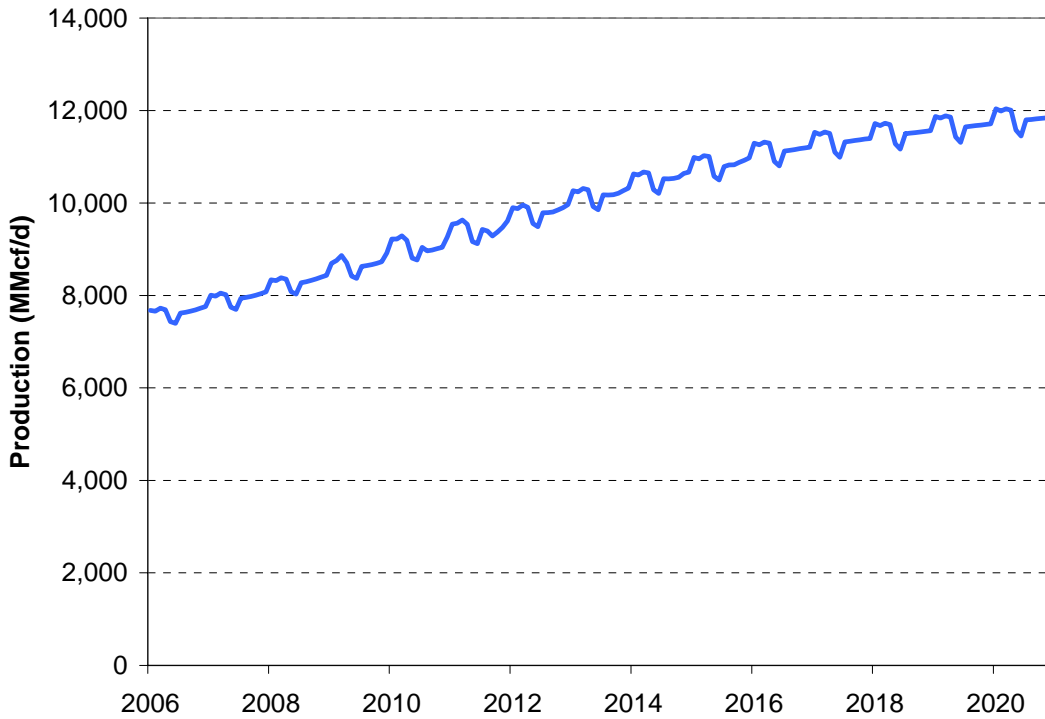
### **Rocky Mountain**

The Rocky Mountain producing region encompasses conventional and unconventional producing formations in Wyoming, Montana, Utah, most of Colorado, and the Raton basin in northern New Mexico, but excludes the San Juan basin. Production has grown robustly from 3.5 Bcf/d in 1996 to the current level of about 6.7 Bcf/d. Proved reserves have almost doubled during this period to more than 35 Tcf. E&P in the Rocky Mountain supply region is supported by the relatively large concentration of undeveloped resources in both conventional and unconventional gas formations.<sup>7</sup> The growth in Rocky Mountain production is expected to continue over the forecast horizon reflecting increased production of coalbed methane in the Powder River Basin in Wyoming and the Raton Basin, among others. Also making large contributions to growing regional production will be gas from tight sand formations in the Green River, Wind River, Piceance, Uinta, and Denver Basins. By 2020 Rocky Mountain gas production is expected to reach almost 12 Bcf/d.

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<sup>7</sup> The unconventional resource base in the Rocky Mountain region amounts to 231 Tcf, 46 Tcf in coalbed methane and 185 Tcf in tight sands and shales.

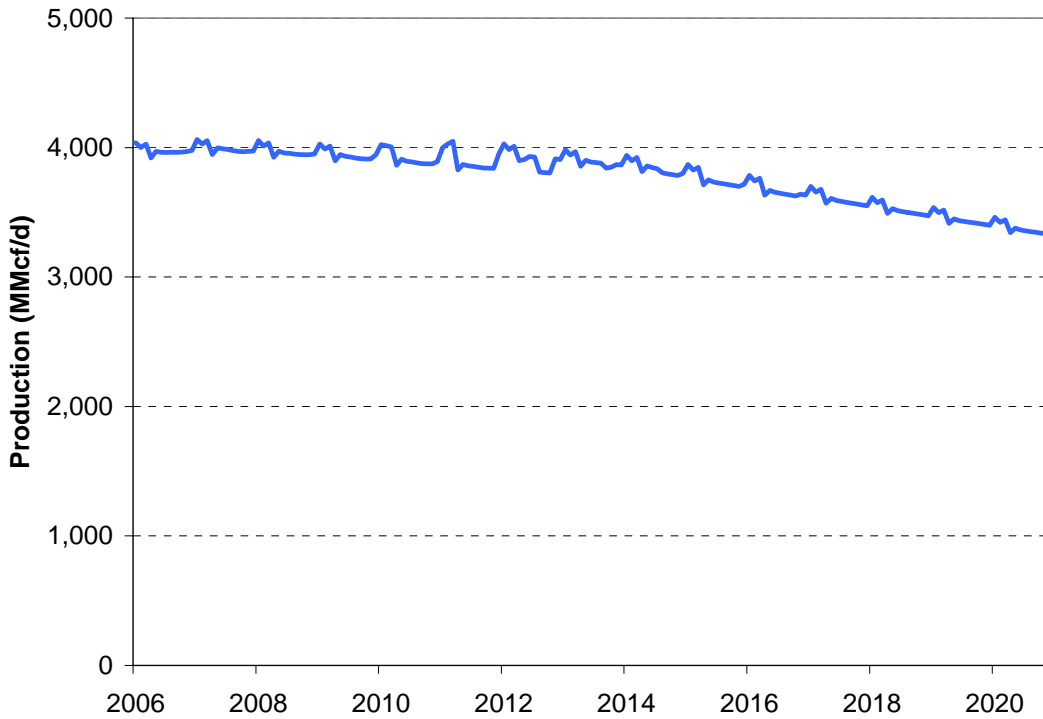
**Figure A2-8 – Rocky Mountain Production**



**San Juan Basin**

In response to legislative tax incentives adopted by Congress in the 1980's to promote the production of coalbed methane, the San Juan Basin has been a major producing basin. Located in northwestern New Mexico and southwestern Colorado, production involves traditional sandstones, tight formations and coalbed methane. Conventional formations represent only 3% of the estimated resources of 68 Tcf. Coalbed methane and tight sands represent most of the remaining resources. Coalbed methane production has allowed overall basin production levels to increase from 3.5 Bcf/d in the mid-1990s to about 4 Bcf/d in 2004. Coalbed methane production, primarily from the Fruitland formation, has reached its peak. However, the long decline curves for the coalbed methane wells along with continued development of other unconventional formations will result in steady to slightly declining production going forward. By 2020 production in the San Juan Basin is projected to be about 3.5 Bcf/d.

**Figure A2-9 – San Juan Production**



### **Mid-Continent**

The Mid-Continent supply region includes producing fields located primarily in Oklahoma, Kansas and parts of northern Texas, including the Texas Panhandle (Texas Railroad Commission Districts 9 and 10). Overall production in the region declined only slightly from 7.8 Bcf/d in 1996 to the current level of production of 7.5 Bcf/d. In Oklahoma, the primary producing basin is the Anadarko Basin, which accounts for more than 80% of production in Oklahoma. The Anadarko Basin is a mature basin, although recent high prices have allowed more drilling and production from deep formations, keeping production about flat in recent years. The largest production declines in the region have occurred in Kansas and in the Texas Panhandle where fields are maturing.<sup>8</sup> Production in Kansas has long been dominated by the Hugoton Field, once one of the largest gas producing fields in North America when production peaked in 1970. Hugoton production declined until the mid-1990s when new rules permitting more infill drilling and compression allowed the field to reach a second lower peak in 1996. Since 1996, Hugoton production has declined at an average annual rate of 8%. In the other portion of the Mid-Continent region,<sup>9</sup> production has grown significantly from 285 MMcf/d in 1996 to 1 Bcf/d in 2004. This growth has been primarily the result of the Barnett Shale developments.

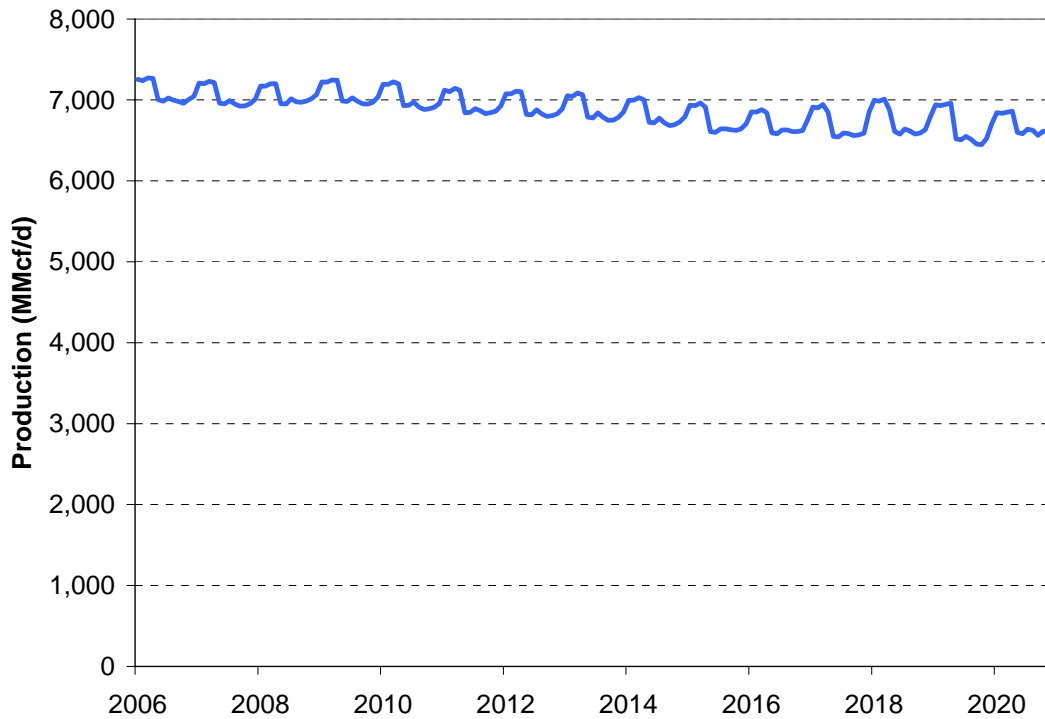
The current production trends are to continue for the foreseeable future and will be augmented by new coalbed methane production from the Cherokee basin in southeastern Kansas and

<sup>8</sup> Texas Railroad Commission District 10.

<sup>9</sup> Texas Railroad Commission District 9.

northeastern Oklahoma. Mid-continent proved reserves have increased by almost 7% since 1996 with the rapid growth of reserves in the Barnett Shale along with increases in the region's coalbed methane and deep Anadarko gas reserves offsetting the rapid decline in Hugoton and Texas Panhandle reserves. Mid-continent production is expected to slowly decline from current levels, reaching 6.6 Bcf/d by 2020.

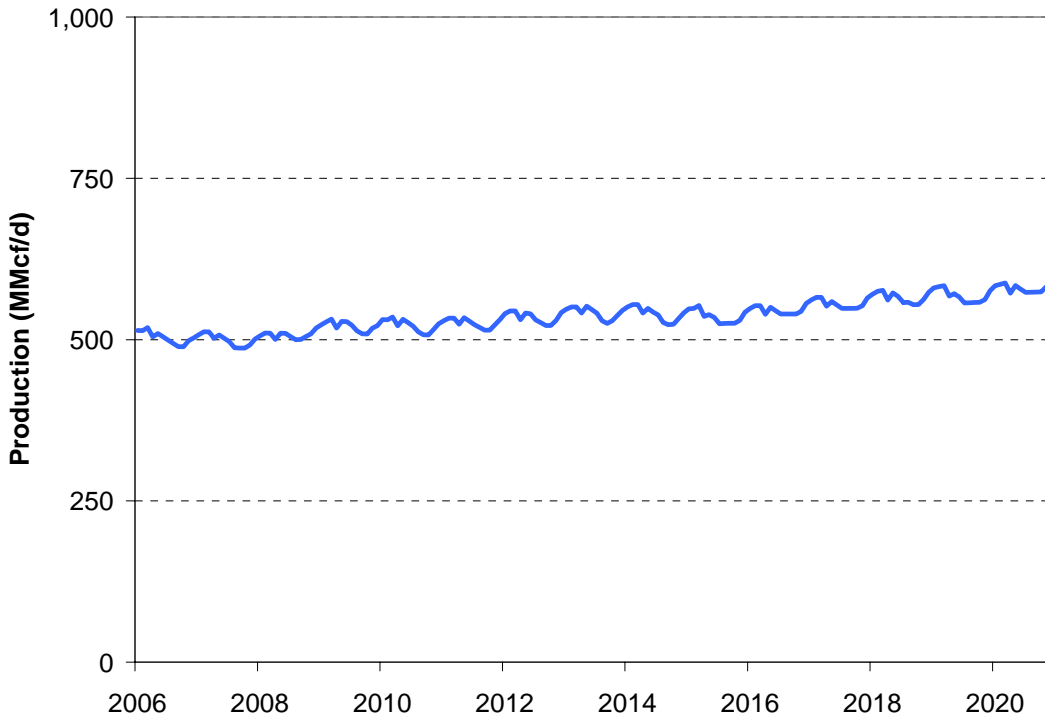
**Figure A2-10 – Total Mid-Continent Production**



### North Central

The North Central supply region includes gas production from Michigan and North Dakota. Total production in the region has averaged about 700 MMcf/d since the mid-1990s while proved reserves have increased about 50%, primarily as the result of increased exploration and development in the Antrim shale of Michigan. Production in the Williston Basin in North Dakota has remained fairly steady at around 140 MMcf/d since 1996. While this basin is estimated to hold approximately 10 Tcf of tight sand and shale gas resources, the primary focus of recent E&P activity has been oil production from the Bakken shale formation. Overall, North Central gas production is expected to drop slightly and then increase gradually around 2010. At the end of the forecast period we have estimated North Central production to be 600 MMcf/d.

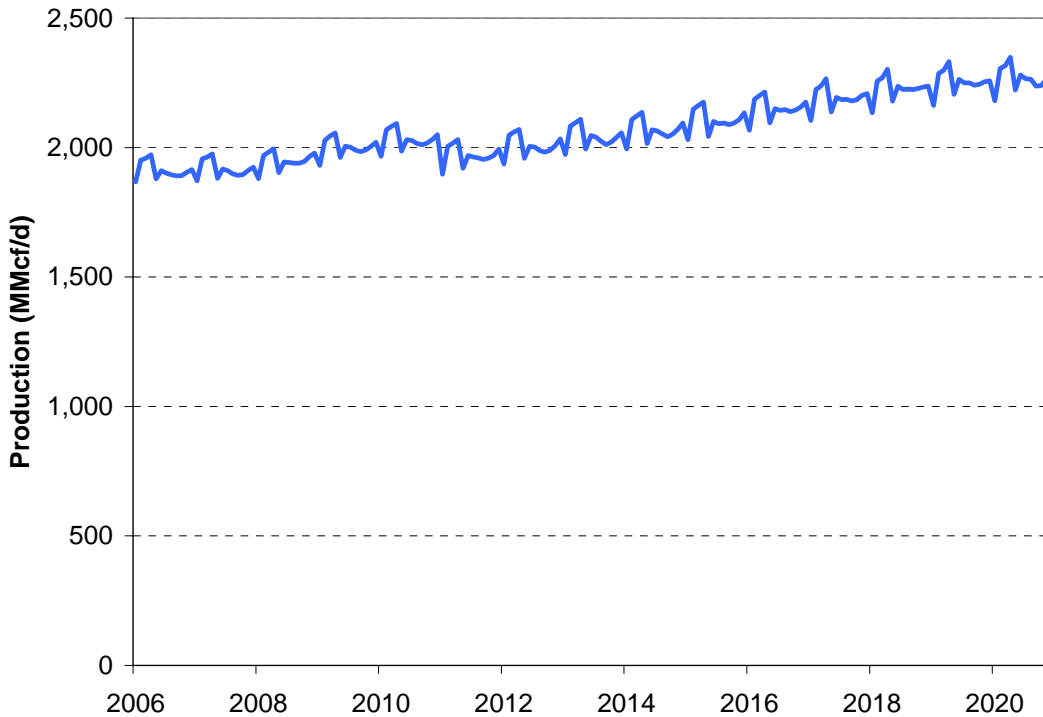
**Figure A2-11 – North Central Production**



**Appalachian Basin**

The Appalachian Basin has a long history of production from fields in Kentucky, New York, Ohio, Pennsylvania, Virginia, West Virginia and the Black Warrior Basin in Alabama. The primary producing formations have included conventional sandstones and carbonates as well as Devonian shale, coals and tight sands. Improved drilling and production techniques and new seismic technology has led to a renaissance in the region with production, which has grown about 10% since the mid-1990s, currently at just less than 2 Bcf/d. Future production will be dominated by unconventional sources with the estimated resources of 104 Tcf in the region consisting of 9% conventional formations, 61% tight sands, 18% Devonian shales and 12% coalbed methane. Production is projected to increase over the forecast period reaching about 2.3 Bcf/d by 2020.

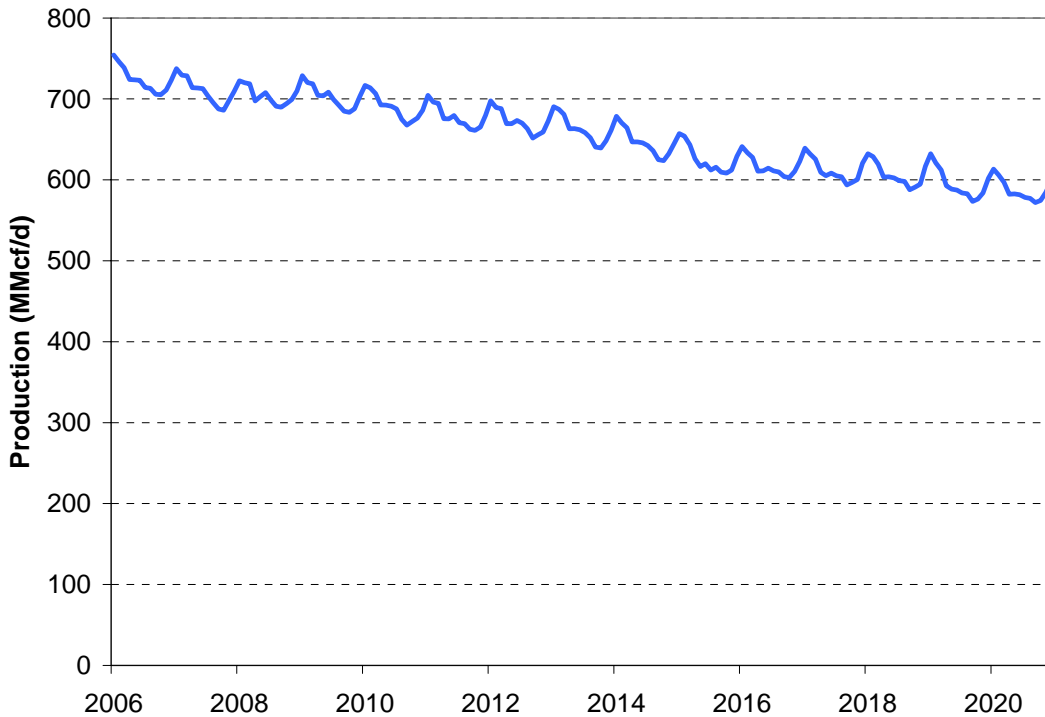
**Figure A2-12 – Appalachian Basin Production**



**California**

California gas production involves mostly associated production from the oil fields in central and southern parts of the state and production from non-associated fields in the Sacramento Basin. A small amount from offshore fields is projected. Associated production accounts for about 75% of the total. Current production of around 800 MMcf/d represents an 11% increase from the mid-1990s. Proved reserves have declined by 11% over the same period. Associated production, driven primarily by the price of oil and the amount of oil produced through enhanced recovery in the fields around Bakersfield, grew from the mid-1990s through 2001. Since then the decline trend has been well documented. Non-associated production has been in decline since the early 1990s. Total California production is projected to decline to around 600 MMcf/d by 2020.

**Figure A2-13 – California Production**

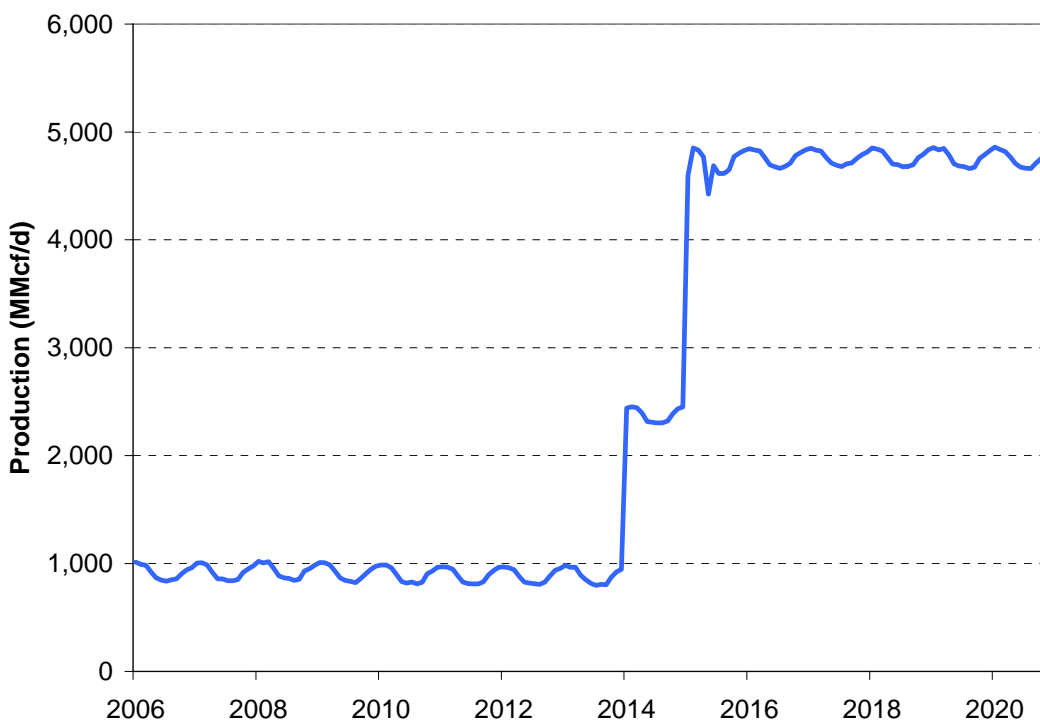


**Alaska**

Alaska gas resources and production are split between the southern production around the Cook Inlet and the North Slope. Current marketed gas production is around 1.1 Bcf/d, with about 570 MMcf/d from Cook Inlet and the rest representing net production from the North Slope. Most of the North Slope gas production is used for lease operations at the oil fields for power generation, oil field compression and pipeline pump stations. Approximately 8.7 Bcf/d, which is not included in net production, is produced in association with North Slope oil production and is re-injected into the oil reservoirs to help maintain oil production. Current proved reserves are 8.3 Tcf, with 2 Tcf in the Cook Inlet region and the rest on the North Slope. There is another 30-40 Tcf of discovered gas resources on the North Slope that cannot be considered proved reserves until either a pipeline or a liquefaction terminal is in place.

Production from the reserves on the North Slope will help offset a portion of the overall decline in domestic production. However, commercializing this resource base is dependent on the construction of a new pipeline from the North Slope to existing pipeline infrastructure, probably Alberta. In LAI's Business-as-Usual Case, we assume that the pipeline will be built by 2013, thereby allowing up to 4.4 Bcf/d to flow by 2015. Alaska gas production will be less than 5 Bcf/d after 2015 as Cook Inlet production is projected to decline significantly over the forecast period. Given the uncertainty associated with predicting the potential decline in Cook Inlet production, as shown in Figure A2-14 we have assumed a relatively level production pattern from 2015-2020.

**Figure A2-14 – Alaska Production**



### **Western Canada Sedimentary Basin**

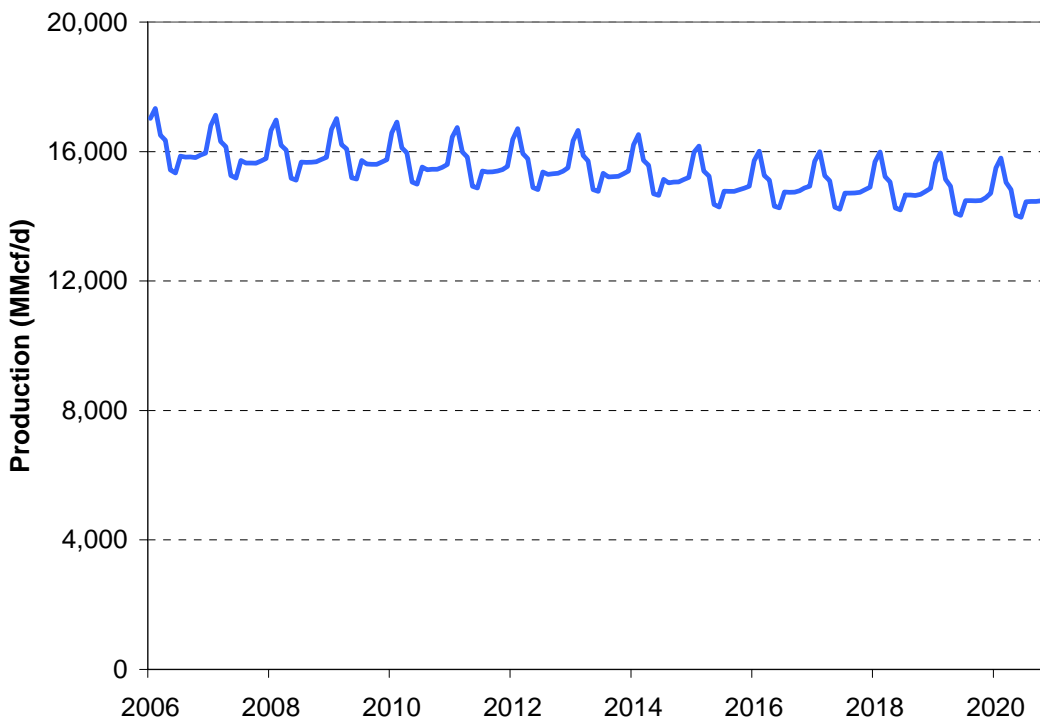
The WCSB covers production from Alberta, Saskatchewan, and British Columbia. The WCSB is one of two primary basins serving New York. The WCSB is a mature producing basin that will likely struggle to maintain current production levels partly as a result of the natural gas intensive process of producing oil from tar sands in Alberta. The WCSB currently accounts for more than 97% of Canada's gas production --nearly all of the gas exported to U.S. markets. Geological formations containing hydrocarbons show increasing drilling depths and geological complexity moving east to west. Drilling will transition from the shallow reservoirs of western Saskatchewan and eastern Alberta to deeper, more expensive fields in western Alberta and British Columbia. Although coalbed methane production in the WCSB is well behind U.S. coalbed methane production in the San Juan and Rocky Mountains, it is expected to grow rapidly in the WCSB, thus partly offsetting depletion trends in the shallow reservoirs. Whereas U.S. coalbed methane production presently accounts for 4.7 Bcf/d, coalbed methane production in the WCSB is projected to exceed 1.0 Bcf/d by 2010.

Total WCSB production is expected to remain flat at around 16 Bcf/d through 2010. Subsequently, a slight decline is predicted. About 15 Bcf/d is predicted through 2020.<sup>10</sup>

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<sup>10</sup>Adjustments to the GPCM database are largely consistent with the recent WCSB production forecasts by TransCanada, a 50% owner of Broadwater.

**Figure A2-15 – WCSB Production**

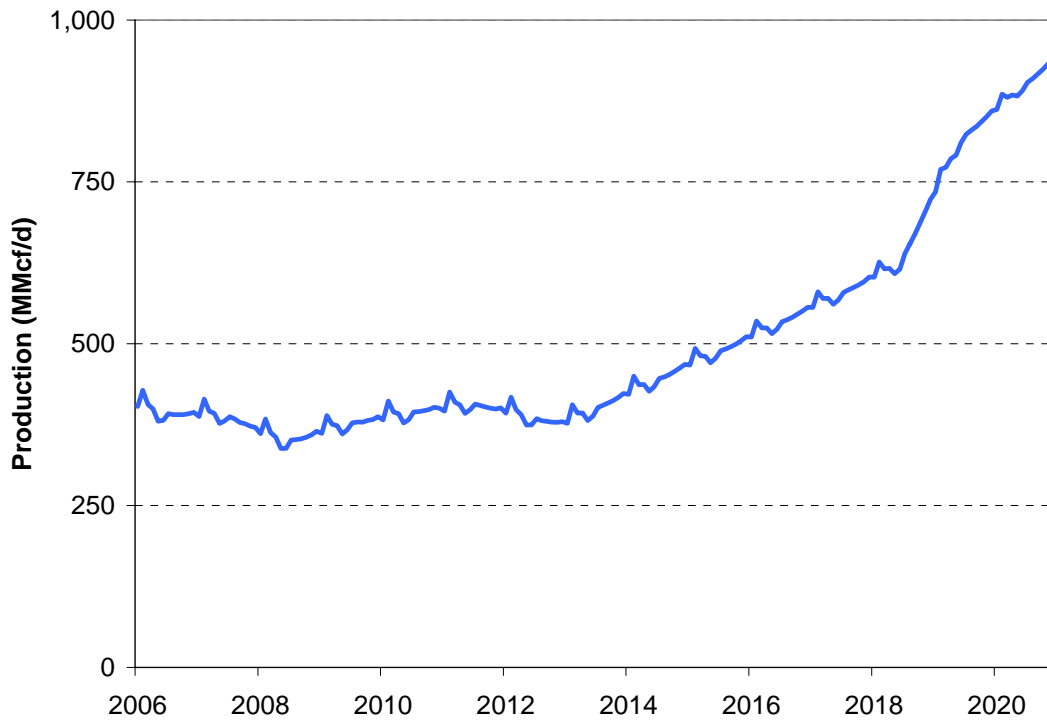


### **Atlantic Canada**

Production from this supply basin began in late 1999 from the Sable Offshore Energy project, located on the Scotian Shelf off of Nova Scotia, at a rate of approximately 500 MMcf/d. The Maritimes and Northeast Pipeline provides a direct pathway from Nova Scotia to New England enabling physical or financial access to the basin for shippers on Algonquin and Texas Eastern. Until late 2003, producers in Atlantic Canada had high hopes that the Scotian Shelf would become a major supply basin for the Maritimes and New England, with production reaching 2 Bcf/d by 2010. Although initial producer enthusiasm in the Scotian Shelf drew industry comparisons to the potential for another “Gulf of Mexico,” the area is highly unlikely to approach Gulf productivity over the forecast period. Over the last three years, exploration and development efforts on the Scotian Shelf have experienced a number of setbacks as producers encountered expensive dry holes, higher than expected infrastructure costs, and several reserve write-downs. These developments signal reduced expectations regarding the potential for any increase in production from Atlantic Canada for the foreseeable future.

The current outlook assumes that production remains around 400 MMcf/d through about the middle of the next decade. The addition of Deep Panuke along with minor production from onshore Nova Scotia and New Brunswick, and incremental gas production associated with oil field production offshore Newfoundland, result in increased production beginning in 2014. At the end of the forecast period, production is 900 MMcf/d.

**Figure A2-16 – Atlantic Canada Production**



## APPENDIX 3

### FUEL PRICE FORECASTS

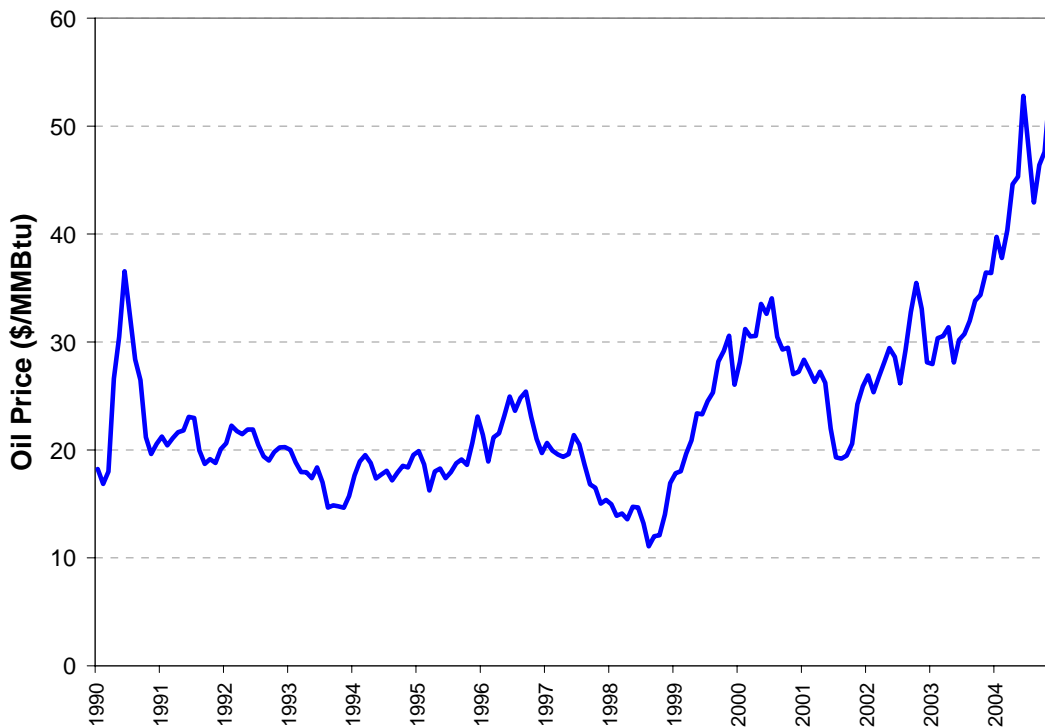
LAI develops fuel price forecasts include based on a range of econometric, statistical and simulation modeling approaches. The forecast for natural gas prices utilize the GPCM modeling system described previously. The forecast for oil includes two components, a near-term forecast and a long-term trend. The near term outlook for light sweet crude oil (equivalent to West Texas Intermediate, WTI) is derived from New York Mercantile Exchange (NYMEX) futures. No. 2 heating oil at New York Harbor (NYH) is derived from the WTI price forecast and then compared for consistency with the NYMEX futures for No. 2 fuel oil. The price of RFO is derived from the crude oil price forecast since RFO prices are also highly correlated to the price of crude oil.

Near term coal and emission allowance prices are based on reported forward prices. Long-term coal price forecasts reflect the production and market conditions that determine free on board (FOB) supply basin prices for the two major coal producing regions of relevance: Northern Appalachia (NAPP) and Central Appalachia (CAPP). These price forecasts, with subsequent adjustments for transportation costs, drive the price of coal delivered to generating plants in New York, PJM and New England. The longer-term forecast for each fuel of relevance over the planning horizon represents LAI's perspective. Statistical analyses has been performed to account for historical production, consumption and price trends, fuel price parity relationships, technology progress, and resource maturational effects.

#### **Fuel Oil**

The price of WTI oil reflects world crude oil prices. WTI prices have experienced booms and busts (Figure A3-1). Most, but not all boom periods have been followed by plateaus or busts. The range between the peaks of the boom periods and the troughs can be substantial. Most recently, oil prices blew through one resistance level after another, reaching \$55 bbl in October 2004. We have incorporated monthly volatility into our WTI forecasts for each scenario based on recent historical volatility patterns. The booms have been driven by supply concerns usually accompanied by political turmoil in one or more of the primary producing regions of the Middle East or Africa. High prices during these periods have spurred investment in E&P, subsequently resulting in increased production at about the time the high prices reduced demand. The Organization of the Petroleum Exporting Countries (OPEC)-led cartel restraints on supply have usually wavered, causing acute gyrations in world benchmark prices.

**Figure A3-1 – WTI Crude Oil Prices**



Against the backdrop of the Iraq war and political chaos in a number of producing countries, global market dynamics have caused a paradigm shift. Some have said a “fear premium” ascribable to continued concerns about destabilization in the Middle East is embedded in current world oil prices. Political instability in Venezuela exacerbates the tension. The long-run trend remains materially above the historical bust levels and materially above the average prices seen over the last three decades.<sup>1</sup> One factor driving the paradigm shift is based on concerns that world oil production has peaked just as the world demand for refined products for transportation fuels has grown, in particular, in India and China. Some analysts contend that oil reserves and production capacity in Saudi Arabia are overstated and therefore future production increases necessary to meet growing demand, based on abundant Saudi reserves, will not materialize.<sup>2</sup> Supporting the expectations for a higher level of prices in the future are recent moves by OPEC to adjust production policies to support prices at levels around \$40/bbl.<sup>3</sup>

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<sup>1</sup> Over the forecast period upward pressure on oil prices, driven by steady demand for refined products from the industrialized economies and by robust demand in China, India and other developing economies, will be tempered by increased production from non-OPEC fields (Russia and the Caspian Sea). Production in Canada from oil sands will also figure significantly in U.S. imports. Stringent emissions limits on RFO may also have a moderating influence on demand growth. In LAI’s view, production peaks in the Middle East and Africa are likely to sustain significant real upward pressure on prices through 2020.

<sup>2</sup> Matthew R. Simmons, *Twilight in the Desert: The Fading of Saudi Arabia’s Oil*. Presentation to the Hudson Institute, September 19, 2004.

<sup>3</sup> Factor inputs for all models were based on market expectations and geopolitical considerations as of July 2005. The run up in oil and gas prices following Hurricanes Katrina and Rita have not been included in this analysis.

In consideration of the possibility that oil prices could move higher from current levels, a forecast of higher oil prices is included in our High Price Scenario. The Business-as-Usual Case incorporates a long-term real price escalation of 0.8% per year.

The primary factor affecting the price of residual or distillate fuel oil is the price of crude. Other cost factors relate to refining and emissions limits. Current refinery configurations limit the volume of heavy, high sulfur (sour) crude that can be processed, while environmental restrictions are limiting capacity expansions and additions. The forecasts of residual fuel oil and distillate fuel oil are based on historical relationships with the price of WTI, the NYMEX futures prices for light sweet crude (equivalent to WTI), and the futures prices for No. 2 heating oil. The forecasts for NYH prices for 0.3% and 1% sulfur RFO along with No. 2 fuel oil are derived from the statistical correlations with benchmark crude. The No. 2 oil futures strip is utilized as a check for consistency with the results of the econometric analysis.

For the near term, the Business-as-Usual crude oil forecast utilizes NYMEX futures prices through December 2011.<sup>4</sup> We then assume that crude oil prices will escalate at a real rate of 0.8% annually – consistent with the EIA’s forecast of long-term real price escalation in the 2005 Annual Energy Outlook – or about 3.9% per annum in nominal terms. Kerosene prices for gas turbines on Long Island and New York City were forecast based on an analysis of the historical premium for kerosene over No. 2 fuel oil. Delivered fuel oil prices in New York reflect applicable taxes.<sup>5</sup>

In Table A3-1, we summarize the price adjustments to the NYH price used to obtain the price of RFO and No. 2 fuel oil in New England and PJM.

**Table A3-1 – Regional Fuel Oil Price Differentials from NYH Forecasts**

<b>Market</b>	<b>Residual Fuel Oil</b>	<b>No. 2 Fuel Oil</b>
PJM	0.7% NYH + \$0.25/MMBtu	NYH + \$0.27/MMBtu
New England	0.7% NYH + \$0.30/MMBtu	NYH + \$0.33/MMBtu

## **Coal**

Coal prices are stated on an FOB basis at the two primary coal supply regions serving New York, PJM and New England. The price of coal is a prime determinant of the price of energy in PJM, in particular. It therefore has a direct effect on LIPA’s cable loading factor on the new high-voltage direct-current cable from New Jersey to Long Island. Individual forecasts have been developed for NAPP and for CAPP (Figure A3-2). The forecast uses econometric models that

<sup>4</sup> As of summer 2005.

<sup>5</sup> The New York Petroleum Business Tax is \$0.39/MMBtu for RFO and \$0.56/MMBtu for No. 2 fuel oil). The New York Spill Tax is \$0.02/MMBtu for RFO and distillate fuel oil.

are based on the historical relationships between the price of coal in these supply regions, underground mining productivity in Appalachia, and inflation.<sup>6</sup>

Coal market prices are heavily influenced by production costs and mining conditions in the NAPP and CAPP mining regions. Underground mining productivity is a key factor affecting production costs in these mining regions since underground mines account for about 65% of the coal produced in NAPP and CAPP. Underground production in these regions is expected to increase market share over the forecast horizon as Appalachian surface mines are depleted and surface mined production declines in response to the environmental restrictions on mountain top removal mining methods.

Contracts with end-users, primarily electric generators, cover 70% of the coal mined in CAPP and 80% of the coal mined in NAPP.<sup>7</sup> The remaining coal purchases are transacted in the spot market. While spot market prices influence contract prices – in some cases serving as the benchmark for the initial price levels in new contracts or for restructured contracts, many large coal users are refusing contracts tied to spot prices. The NAPP and CAPP coal price forecasts were utilized to provide the basis for escalating the cost of coal on a delivered basis to coal-fired plants in New York, New England and PJM. Most of the individual generating plants in each region have a specific mix of spot and contract coal supply arrangements, with specific delivered prices incorporated in MarketSym.<sup>8</sup>

LAI expects the current run-up in coal prices to recede in both CAPP and NAPP in the near term. After 2008, coal prices are expected to increase in nominal terms at 2.1% for CAPP and 2.0% in NAPP, representing a decrease in real terms. These forecasts reflect the total volume of coal mined in CAPP and NAPP purchased under both contracts and in spot markets. Spot prices are likely to be more volatile, and during periods of tightened supplies may exhibit price run-ups similar to the most recent spot market pricing behavior. This reflects a permanent change from the 1985 to 2001 when coal prices declined steadily in nominal terms. Key factors which have reversed the trend of declining coal prices in Northern and Central Appalachia include: recent industry consolidation due to several producer bankruptcies, depletion and closing of several older mines, and a reduction in the increase in mining productivity.<sup>9</sup>

For plants located along the east coast that receive shipments by water, coal imported from Colombia and Venezuela will exert some downward pressure on prices. For plants located in the

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<sup>6</sup> Contract escalators are tied to inflation indices in the United Mine Workers' contracts with the eastern coal producers.

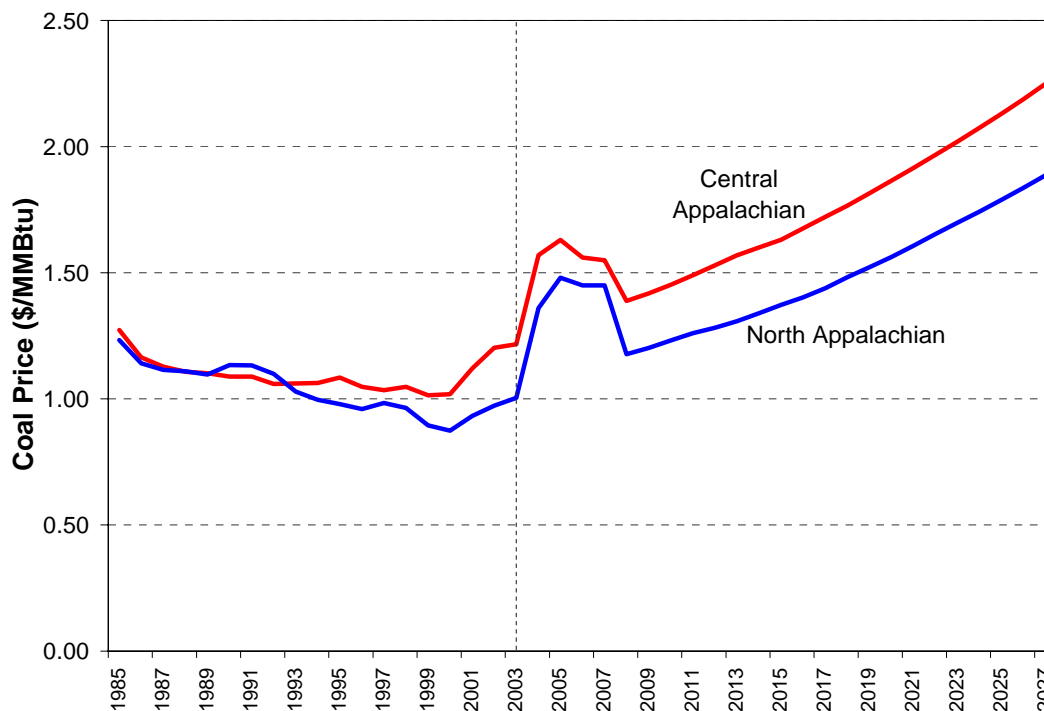
<sup>7</sup> U.S. EIA, U.S. Coal Prices – Northern and Central Appalachian Coal.

<sup>8</sup> These data had been in the public domain through FERC Form 423 reports. However, public disclosure of individual plant fuel cost is no longer compulsory under FERC rules. While LAI's database for regional generating plants runs through 2001, the unavailability of reliable Form 423 data requires a forecast method for consistency.

<sup>9</sup> The growth in mining productivity has declined as longwall mining approaches saturation. Our forecast assumes that underground mining productivity in Appalachia will continue to increase, but at an average rate that is lower than history. This rate of growth averaged 5.8% annually from 1980 to 2001. The forecast assumes that the growth in underground mining productivity for the Appalachian producing regions will average about 1% annually over the forecast period.

western areas of PJM and New York as well as in the mid-west, Powder River Basin coal can exert some dampening influence on prices.

**Figure A3-2 – Historical and Projected Coal Prices**



### Nuclear Fuel

Nuclear fuel prices are forecast to increase at about the rate of inflation through the end of the forecast horizon.<sup>10</sup> These costs are driven by U<sub>3</sub>O<sub>8</sub> prices, which represent about 25% of total nuclear fuel costs, along with the costs of enrichment and fabrication. U.S. U<sub>3</sub>O<sub>8</sub> prices declined from around \$40/lb in the late 1970s to a range of \$10/lb to \$20/lb for most of the last 20 years. Recently, spot prices have soared. Spot prices represent about 12% of the market for nuclear fuel. Most of the remainder is purchased under long-term contracts, with 3 to 7 year contracts being the longest typical positions.

Sufficient supplies of uranium and adequate fuel processing capacity should maintain fuel costs at nuclear plants in New York, PJM and New England at the equivalent of \$0.40/MMBtu throughout the forecast period.<sup>11</sup> This price pattern reflects the impacts of the small number of new plants likely to be built worldwide through 2010. Subsequent increases in demand will depend on the construction of new plants in response to rapidly growing power demand in the developing countries, especially China and India, and, conceivably, potential new plants in the U.S. and Europe to combat global warming.

<sup>10</sup> Nuclear fuel supply is comprised of mined and enriched U<sub>3</sub>O<sub>8</sub>, utility stockpiles of uranium, and secondary sources such as recycled spent fuel and recycled weapons grade uranium and plutonium.

<sup>11</sup> 2003 dollars.

## APPENDIX 4

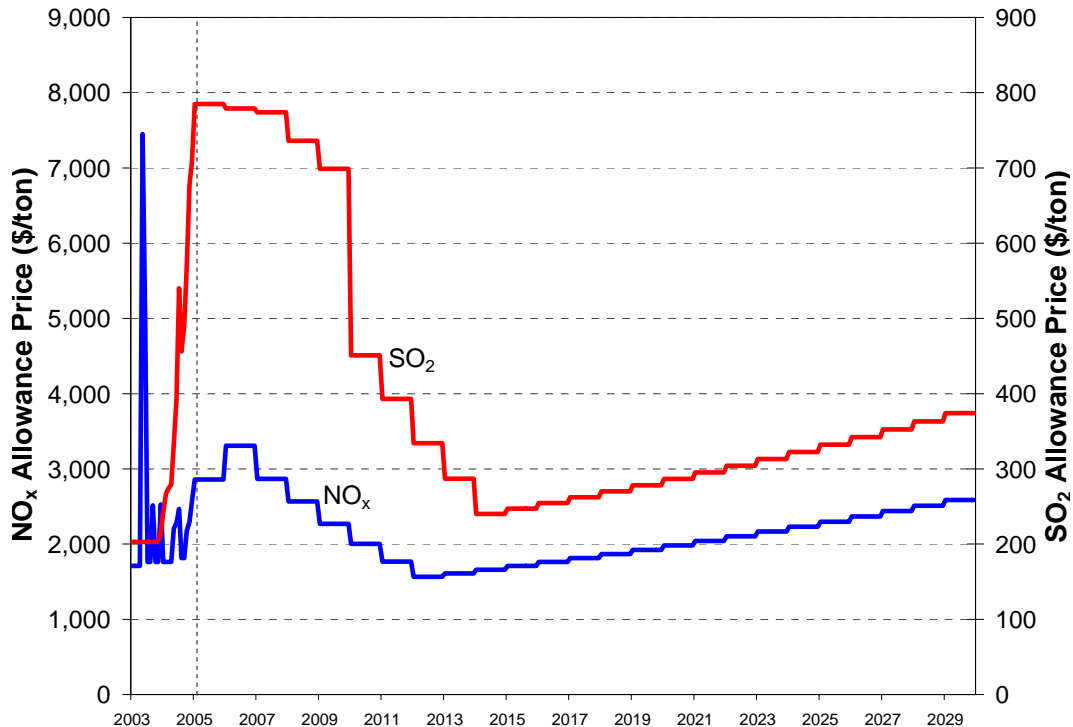
### EMISSIONS ALLOWANCE PRICE FORECASTS

#### SO<sub>2</sub> Allowance Price Forecast

Until 2003, SO<sub>2</sub> allowance prices remained stable in a relatively narrow bandwidth of \$100-\$200/ton. In 2004, SO<sub>2</sub> allowance prices soared to over \$700/ton in anticipation of the promulgation of CAIR and the Clean Air Mercury Rule. Uncertainty over the form and stringency of mercury limits affecting existing coal-fired plants coupled with uncertainty concerning the actual impacts of CAIR, caused power generators to delay planned FGD technology retrofits and forced these generators to rely more heavily on allowances to meet compliance requirements. Spot prices briefly exceeded \$1,600/ton following promulgation of CAIR in 2005.

The forecast of SO<sub>2</sub> allowance prices, presented in Figure A4-1, was based on forward price curves available at the time the forecast was developed. Prices were forecast to remain in the \$700/ton vicinity through 2007, then gradually decline to historical values of \$200/ton by 2014, as many of the generators implement scrubber retrofits. After 2014, allowance prices were forecast to escalate at a rate comparable to inflation.<sup>1</sup>

**Figure A4-1 – Emissions Allowances Price Forecast**



<sup>1</sup> Market prices for SO<sub>2</sub> allowances are based on prices reported by Evolution Markets, as of July 2005.

## **NO<sub>x</sub> Allowance Price Forecast**

The NO<sub>x</sub> allowance price forecast reflects the costs of meeting increasingly stringent NO<sub>x</sub> emission limits, coupled with the proliferation of NO<sub>x</sub> budget programs across the Northeast. Historically, the market price of NO<sub>x</sub> emissions allowances has been related to the marginal cost of NO<sub>x</sub> control technology. However, upward excursions from this level have historically preceded reductions in the statewide NO<sub>x</sub> budgets, as plants have scrambled to retrofit NO<sub>x</sub> emissions controls technologies, primarily SCR, selective non-catalytic reduction (SNCR), and gas reburning, or have acquired sufficient allowances from the market. For example, in the months preceding program implementation in 1999 and again prior to the May 2003 budget reductions, the cost of NO<sub>x</sub> allowances exceeded \$7,000/ton. NO<sub>x</sub> allowance prices have since trended downward.

In Figure A4-1, NO<sub>x</sub> allowance prices reflect the average prices for allowances to be used through 2008, reported for Ozone Transport Commission trades at the time the forecast was developed.<sup>2</sup> Allowance prices were forecast to increase from the 2004 level of \$2,290/ton to \$3,340/ton in 2006. Beyond 2006 allowance prices were forecast to decline through 2012 to reflect the marginal cost of NO<sub>x</sub> control, about \$1,500/ton. After 2012, allowance prices were assumed to escalate with inflation.

Non-ozone season NO<sub>x</sub> allowances under New York's ADRP cannot be traded with ozone season allowances. However, generators can manage fuel burns and emissions inter-seasonally to minimize environmental compliance costs. LAI therefore assumed that the non-ozone season NO<sub>x</sub> allowance prices under ADRP will follow a similar trend as ozone-season NO<sub>x</sub> allowance prices.

## **Mercury**

Concurrent with CAIR, the EPA issued the Clean Air Mercury Rule, which restricts emissions of mercury from coal-fired generating plants. The proposed implementation plan would establish a cap-and-trade program for mercury. Consideration of mercury emissions restrictions may have a material impact on energy prices and installed capacity values in PJM, and to a lesser extent in NYISO.

The first compliance date under this rule, 2010, is intended to be synchronized with the first CAIR milestone to take advantage of fact that SO<sub>2</sub> removal technologies are also effective, to an extent, for mercury emissions control. We expect that coal-fired generators will achieve the first level of mandated reductions in 2010 by installing the same technologies that will be required to meet CAIR limits: SCR and FGD. Mercury removal tests have indicated that the combination of wet FGD and SCR systems, with minor system adjustments and adding small amounts of reagent, can achieve mercury emissions removal efficiencies on the order of 80% to 85%, more than sufficient to meet the Phase I and possibly Phase II mercury limits under the Clean Air Mercury Rule. The key process for achieving mercury removal appears to be the wet FGD system. Early tests using dry FGD systems have not shown similarly high levels of mercury

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<sup>2</sup> Market prices reported by Cantor Environmental Brokerage, December 2004.

removal. In this regard, our attrition analysis of the coal-fired plants in PJM is focused on the added capital and operating costs associated with retrofitting a wet FGD system along with SCR. The existing plants that have not added wet FGD and SCR systems are assumed to incur the costs to retrofit and operate these systems for compliance with mercury emissions limits by 2010.<sup>3</sup> Table A4-1 summarizes the capital and operating costs we utilized for the retrofit of wet FGD and SCR systems. Table A4-1 also includes estimated costs for SNCR retrofits. In order to develop these estimated costs, LAI reviewed reported costs for specific plants' retrofits of SCR, SNCR as well as wet FGD systems.

**Table A4-1 – Capital and Operating Costs for FGD, SCR and SNCR Retrofits on Coal-fired Generating Plants**

<b>Emissions Control System</b>	<b>Capital Cost (\$/kW)</b>	<b>Variable O&amp;M (\$/MWh)</b>	<b>Fixed O&amp;M (\$/kW-year)</b>	<b>Parasitic Load (%)</b>
Wet FGD (LSFO) <sup>4</sup>	175	1.10	6.50	2.0
SCR	100	0.605	0.30	N/A
SNCR	20	0.50	0.15	N/A

## CO<sub>2</sub>

The Regional Greenhouse Gas Initiative (RGGI) is a regional cap-and-trade program that will affect approximately 300 power plants in ten northeastern and mid-Atlantic states that have signed the Memorandum of Understanding (all of New England, New York, New Jersey, Maryland, and Delaware) The program establishes annual state-wide caps for CO<sub>2</sub> emissions from fossil-fueled plants, 25 MW and larger. The program is designed to commence in January 2009, with a target of stabilizing CO<sub>2</sub> emissions at current levels through 2014, and then achieving reductions of 2.5% per year through 2018.

At the time LAI developed the MarketSym model, the RGGI Model Rule had not been framed, it was uncertain whether RGGI would eventually become an enforceable regulatory framework, and the prospect of a federal carbon control policy appeared remote. For purposes of our electric simulation model, in our base scenario we assumed the *status quo*, *i.e.*, that there are no enforceable state or federal controls on CO<sub>2</sub> emissions. We also developed an alternate “CO<sub>2</sub> tax” scenario to assess the impact of some type of regulatory controls on CO<sub>2</sub> emissions. The combustion of all fossil fuels emits CO<sub>2</sub>, but coal-fired generation is impacted disproportionately to gas-fired generation under such regulation. In this scenario, \$10 per ton of CO<sub>2</sub> (escalated)

<sup>3</sup> The use of these control technologies will allow the plants to reduce NO<sub>x</sub> and SO<sub>2</sub> emissions allowance costs and more easily meet the more stringent SO<sub>2</sub> and NO<sub>x</sub> emissions limits as well as to comply with the mercury limits. Any plants that cannot meet the cash flow threshold requirements utilized in the attrition analysis as the result of the added costs associated with wet FGD and SCR retrofits are assumed to be retired.

<sup>4</sup> Limestone forced oxidation

<sup>5</sup> Does not include catalyst replacement costs of \$9.75/kW every 5 years.

will be assessed on emissions from all fossil generation beginning in 2010.<sup>6</sup> This cost can be represented as a tax (if future legislation is structured to be an assessment on output), an emission allowance cost, or the opportunity cost of trading allowances.

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<sup>6</sup> In 1999, the average CO<sub>2</sub> emissions in the U.S. was 2.1 lb/kWh for coal plants, 1.9 lb/kWh for oil-fired plants, and 1.3 lbs/kWh for gas-fired plants. At \$10/ton, this equates to \$10.50/MWh for coal, \$9.50/MWh for oil, and \$6.50/MWh for gas. U.S. EIA, *Carbon Dioxide Emissions from the Generation of Electric Power in the United States*, July 2000.

## **APPENDIX 5**

### **APPLICATION REVIEW, INCLUDING RESOURCE REPORTS**

Broadwater announced the Project in November 2004, and at that time, FERC granted Broadwater's request to use the National Environmental Policy Act (NEPA) pre-filing review process for the Project. Four FERC and USCG public scoping meetings were held, as well as numerous stakeholder meetings with the public, local, state and federal agencies.

Broadwater filed its application for Certificate of Public Convenience and Necessity with FERC on January 30, 2006. In the application, Broadwater requested that the Commission issue a final order granting it all necessary authorizations by March 31, 2007. Broadwater also requested waivers of "any and all Commission regulations necessary to obtain expeditious approval of Broadwater's application." The application consists of sixteen volumes. The application Volume contains the transmittal letter, the application, the Form of Notice and Exhibits A, B, C, G and H. Volumes I – VI contain the Resource Reports for the onshore and offshore facilities. These volumes are public. Volume VII contains the Privileged and Confidential portions of Resource Report 4 and Resource Report 5. Volumes VIII – XIV contain Critical Energy Infrastructure Information of Resource Report 9 and Resource Report 13. Volume XV contains the Sensitive Security Information of Resource Report 8 and Resource Report 11.

The Resource Reports consist of the following documents:

- Resource Report 1 – General Project Description
- Resource Report 2 – Water Use and Quality
- Resource Report 3 – Fish, Vegetation and Wildlife
- Resource Report 4 – Cultural Resources
- Resource Report 5 – Socioeconomics
- Resource Report 6 – Geological Resources
- Resource Report 7 – Soils
- Resource Report 8 – Land Use, Recreation and Aesthetics
- Resource Report 9 – Air and Noise Quality
- Resource Report 10 – Alternatives
- Resource Report 11 – Safety and Reliability
- Resource Report 12 – PCB Contamination (not applicable to Broadwater)
- Resource Report 13 – Engineering and Design Material
- Onshore Facilities Reports
- Environmental Sampling Report

LAI reviewed only the publicly available Resource Reports as part of our review of the Project. Due to federal security regulations, Resource Report 13 and some parts of the other reports are subject to restricted distribution and were not available to LAI.

FERC regulations require the applicant to show that the Project is “not inconsistent with the public interest.” Broadwater asserts that:

- The Project will improve access to supplies of natural gas to serve new market demand.
- The Project will not impair the ability of Broadwater to render transportation service at reasonable rates to existing customers.
- The Project will not involve any existing contracts between Broadwater and a foreign government or person concerning the control of operations or rates for the delivery or receipt of natural gas which may restrict or prevent other U.S. companies from extending their activities in the same general area.

The Resource Reports are summarized below, with the exception of Resource Report 11, which is discussed in Section 5.8 of the main report.

### **Resource Report 1 – General Project Description**

Resource Report 1 describes the proposed Project siting, purpose and need, land requirements, construction procedures, operation and maintenance plans, environmental permits and approvals required, decommissioning, removal and abandonment. A list of required permits for the Project can be found at the end of this Appendix.

In this Resource Report, Broadwater examines the volatility in natural gas prices ascribable to capacity constraints in the gas transportation infrastructure into the region, as well as to the increasing reliance on natural gas for electric power generation in New York and Connecticut. Broadwater concludes that without the Project, New York and Connecticut will experience rising price trends and volatility because they are positioned at the end of the continental gas transportation system. Broadwater cites EIA forecast data (especially the 2005 AEO) in its analysis as well as a study by Energy and Environmental Analysis, Inc. (EEA). Resource Report 1 does not provide a forecast of regional gas prices with and without Broadwater.

Some highlights of this report are:

- Flows of up to 600 to 700 MMcf/d could be physically delivered to Long Island and/or New York City from Broadwater based on hydraulic simulations of the Iroquois system, with the balance flowing north into Connecticut.
- Temporary onshore land requirements would be within the existing port communities on the New York shore of Long Island Sound. The need for development of new facilities to support the Project is not expected. Throughout the construction phase, a pipe storage yard and concrete coating facility will be located outside the Long Island Sound area, somewhere on the East Coast.

- Permanent onshore facilities will be leased by Broadwater in Greenport and/or Port Jefferson. These facilities will include permanent mooring locations at a port for safe harbor for auxiliary and support vessels and for offloading of crews and/or supplies, warehousing facilities and office space.
- The pipeline route will cross two utility cables, both buried six to seven feet below the natural seabed: the AT&T fiber optic telecommunications cable and the Cross Sound Cable. Federal regulations require a minimum of 12 inches of separation between the cables and the pipeline (49 CFR Part 192), therefore Broadwater plans to install a crossing bridge over each of the two cables.
- The FSRU will have a double hull design similar to an LNG carrier. The primary barrier is 1.2-mm stainless steel that would be corrugated to compensate for thermal contraction and mechanical ship deflection. The secondary barrier is a laminated composite material consisting of aluminum foil sandwiched between two glass cloths. The insulation consists of rigid polyurethane foam with reinforcing glass fibers between two plywood sheets, the thickness of which is determined to limit the boil-off rate to 0.15% per day with cargo tanks at 98% full.
- Any LNG spill will be directed overboard, away from critical areas and living quarters, where it will dissipate into the atmosphere and have no impact on water quality.
- At the completion of cargo unloading operations, LNG in the loading arms will be drained by gravity either back into the LNG carrier cargo tanks or to the FSRU drain tank from which it will be pumped into the FSRU storage tanks.
- To maintain the hull integrity of the FSRU and the LNG carrier, a constant curtain of water will be directed overboard during LNG transfer.
- The FSRU will be equipped with a flare for emergencies only. The flare will rise 197 ft (60 m) above the trunk deck and will handle vapors in the event of overpressure in the storage system.
- Normal ballast water intake will be about 900 m<sup>3</sup>/hr or 5.7 million gallons per day of seawater to offset a daily vaporization and send-out of 2,000 m<sup>3</sup>/hr. During LNG offloading, the loading rate will be 10,000 m<sup>3</sup>/hr and discharge rate of ballast water will be about 4,500 m<sup>3</sup>/hr. For a 145,000 m<sup>3</sup> LNG shipment, the FSRU would discharge 50,000 m<sup>3</sup> or 13.2 million gallons of water.
- Upon decommissioning, the FSRU will be decoupled from the mooring system and towed to a shipyard to be overhauled for reuse or recycled.

The EEA report entitled “Regional Market Growth and the Need for LNG Imports into the Northeast U.S. and Canada,” is included in Resource Report 1 as Appendix A. This report provides an overview of northeast U.S. and eastern Canadian gas markets, including a breakdown of consumption by market sector in NYC, Long Island, and southern Connecticut. Much of the analysis is focused on national rather than regional trends. In addition to Appendix A, the following are also appendices to Resource Report 1:

- American Bureau of Shipping, Approval in Principle Letter to Broadwater Energy (July 27, 2005)

- Stratford Shoal Contingency Plan

## **Resource Report 2 – Water Use and Quality**

Resource Report 2 describes the groundwater and surface water resources that may be affected by the construction and operation of the Project. It also addresses the proposed installation methods for the FSRU and interconnecting subsea pipeline, and the mitigation measures proposed to minimize the associated water quality impacts.

Long Island Sound is designated by NYSDEC as a Class SA water suitable for commercial shellfishing and primary and secondary recreational fishing. These waters are also suitable for fish propagation and survival. NYSDEC has issued applicable guidelines for thermal discharges and mixing zones.

The report states that impacts on Long Island Sound water quality during construction are expected to be minor, localized and short-term. Impacts associated with operation will be minor but long-term and result from routine intake and discharge of Long Island Sound waters by the FSRU. Sediment sampling conducted in the spring of 2005 suggests that no elevated contamination levels (including polycyclic aromatic hydrocarbons, polycarbonate biphenyls, pesticides, volatile organic compounds – VOCs – and dioxin) are present in proximity to the Project area and that pipeline alignment will be routed to avoid areas with elevated contaminant levels. The lack of significant contamination within the Project area restricts construction impacts to localized, short-term increases in TSS in the water column. Using a subsea plow as the primary means of lowering the pipeline below the seabed will decrease the amount of sediment introduced into the water column compared to other installation technologies and will restrict impacts to temporary increases of TSS in the bottom strata. According to the results of the MIKE3 sediment model provided in this Resource Report, the TSS levels would largely be assimilated throughout the Sound within 12 hours following completion of the plowing.

Strong winds associated with hurricanes and other storms may generate significant waves which can limit FSRU operation. Based on historical data, a 100-year storm event would be expected to have a significant wave height of 14.2 ft (4.3 m) and a 1,000-year storm event a height of 18.8 ft (5.7 m). The yoke mooring system is designed to withstand storm scenarios in excess of the 100-year storm event.

Hypoxia, or low levels of DO, is considered to be the most serious water quality issue in Long Island Sound and is most prevalent in the summer. A total of 597 DO readings with an average value of 9.5 mg/L were collected in April and May of 2005 in the area of the proposed pipeline route. DO levels above 4.8 mg/L are considered excellent and supportive of marine life. The proposed marine pipeline would be installed in the winter months when hypoxic conditions are largely absent from the Sound.

Broadwater expects that the installation of the FSRU will not impair water quality. In accordance with international regulations, the FSRU will be required to complete a ballast exchange prior to entering Long Island Sound to ensure that no invasive species or water of reduced quality are introduced.

The total average daily water intake to support all FSRU operations will be approximately 5.5 million gallons, assuming an annual average of 118 LNG vessels per year. The FSRU is proposed to have up to seven point-source discharges and some non-point discharges, including ballast water discharge, discharge from the desalinization plant, fire water bypass, treated wastewater from on-board sanitary and other systems, seawater cooling discharge, and stormwater runoff. Of these, ballast water comprises by far the largest component of the FSRU's water requirements. The LNG revaporization system will be closed-loop and not require intake or discharge of seawater. To control the growth of marine organisms, the FSRU seawater intakes will include the ability to inject a continuous dose of sodium hypochlorite at a concentration of 0.2 ppm which will result in a residual chlorine concentration between 0.01 and 0.05 ppm at the sea chest and at the ballast water discharge. The Project will meet NYSDEC's SPDES standards for effluent water quality for all discharges.

While the FSRU is discharging ballast water, the LNG carrier will be taking on approximately the same amount of ballast water. The majority of the LNG carriers bringing cargo to the FSRU will be steam-powered vessels and will require approximately 57 million gallons of water for water cooling purposes during a 22 hour offloading process. This discharged cooling water will be approximately 3.6°F (2°C) higher than the ambient water temperature and contain low doses of sodium hypochlorite to prevent the growth of marine organisms. Cumulatively, the LNG carriers will utilize an average of 22.7 million gallons per day, on an annual average, including cooling and ballast water requirements.

Impacts on water quality from operation of the pipeline are expected to be minimal since the pipeline is a closed system. The riser pipe will have contact with the surrounding waters only in the section from the FSRU to the foot of the riser on the seafloor that connects through the mooring tower. Because the temperature of the gas will be 130° F when it exits the FSRU and 120° F at the foot of the riser pipe, there is a potential for heat exchange between the pipeline and the surrounding waters along the exposed riser pipe. However, Broadwater does not expect a thermal plume to develop.

The following are appendices to Resource Report 2:

- Correspondence with NYSDEC for environmental sampling and SPDES permit
- Email approval of the USACE MIKE3 model
- Cadmium clarification memo
- Generic SPCC Plan
- Water quality/sediment quality modeling report
- Grain size analysis May 2005 environmental sampling
- Sediment deposition modeling report
- Natural backfill modeling report
- Thermal modeling report

### **Resource Report 3 – Fish, Vegetation and Wildlife**

Resource Report 3 describes the fish, vegetation, and wildlife existing conditions and habitats. It also addresses the construction and operational impacts of the Project on these resources and the proposed mitigation methods.

The Project and the LNG carrier route will be sited to avoid impacts on significant coastal habitats, specifically the Significant Coastal Fish and Wildlife Habitat areas. Long Island Sound has been designated an EFH, *i.e.* “waters and substrate necessary to fish for spawning, breeding, and feeding or growth to maturity”. Therefore, NOAA’s fisheries unit must be consulted on all proposed activities. The proposed Project would overlap with EFHs for 20 species within or adjacent to the proposed pipeline route.

In April and May 2005, samples were collected at the proposed FSRU location and 27 stations along the proposed pipeline route. A benthic survey and sediment and chemical analyses were conducted at each station. The benthic survey revealed that benthic communities are generally consistent with what would be expected based on depth, substrate, and sedimentary environment.

Ninety five finfish species have been collected between 1984 and 2003 in Long Island Sound as part of the Long Island Sound Trawl Surveys. The proposed FSRU location is at the intersection of four survey squares with mean finfish counts that ranged from 492.3 per tow to 2,879.6 per tow. The mean finfish count along the majority of the proposed pipeline route ranges from 0 per tow to 1,000 per tow. Resource Report 3 provides a detailed discussion of 11 species of finfish and two species of shellfish that have recognized value within the Sound. The Resource Report also describes plankton, reptiles, marine mammals and avian species that frequent the Sound .

According to NOAA Fisheries, there are four species of federally threatened or endangered sea turtles and three whale species in New York waters, most of which are not typically present in Long Island Sound.

Construction and operation of the proposed facilities have the potential to cause both positive and negative effects on the marine environment. Broadwater anticipates that the construction impacts will be short-term and minimized by siting the facility in deep water and installing it during the winter months when use of the Sound by marine species is reduced. Nonetheless, construction will result in the following:

- direct disturbance of bottom sediments,
- direct mortality of most benthic organisms in the path of construction,
- some increase in turbidity levels and suspended solids,
- decreased water quality, and
- acoustic disturbance.

Broadwater points out several positive and operational/long-term impacts resulting from the diversification and expansion of the habitat within the Sound:

- The FSRU would create permanent shaded habitat

- The mooring tower and pipeline would create additional structure in the Central portion of the Sound by creating an artificial reef habitat, which would favor a number of species including lobsters.
- The safety / security zone would exclude fishermen.
- Heat dissipation from the pipeline to the water column could establish a microclimate attracting certain species to that area.

Broadwater also notes long-term negative impacts resulting from the operation of the FSRU and pipeline:

- Pipeline maintenance involving periodic inspection and pigging activities will re-disturb the sediments in the pipeline areas.
- Water intake by the FSRU and LNG carriers will entrain organisms smaller than 5 mm and eliminate them by the sodium hypochlorite injection.
- FSRU discharge will contain chlorine at a concentration of 0.01 to 0.05 ppm.
- Spills or other accidents may occur at the facility.
- Maintenance of FSRU sides to reduce biofouling may impact marine resources.
- FSRU and LNG carriers will cause acoustic disturbance.
- Lighting at the facility has the potential to attract avian species.

Broadwater states that any loss of habitat resulting from installation of the FSRU will be offset by the increased habitat that is created. Resource Report 3 concludes that construction of the facilities is unlikely to significantly impact the population or survival of any species within the area.

The following are appendices to Resource Report 3:

- EFH assessment
- Benthic video survey report
- Benthic laboratory analytical results
- Drop camera video
- Ichthyoplankton entrainment estimates
- Correspondence
- Sediment deposition resulting from construction of a natural gas pipeline trench
- Natural backfilling of natural gas pipeline trench

### **Revised Resource Report 3 – Vegetation and Wildlife**

Broadwater revised Resource Report 3 in response to FERC's request of October 19, 2005. More specific and quantitative information was requested in the following areas:

- Threshold values for turbidity and sedimentation and the extent and duration of high values after construction
- Impact of turbidity and sedimentation on the benthic community
- Anti-fouling paint impacts to marine resources
- Hydrostatic impacts to marine resources
- Noise and acoustic shock impacts on marine mammals, fish and birds
- Impact of water intake and discharge, both ballast and cooling, on ichthyoplankton by season
- Ichthyoplankton abundance and diversity by depth distribution or seasonal occurrence by lifestage
- Plans to minimize lighting impacts to birds and marine mammals
- Impacts to marine mammals or birds due to waste streams or toxic substance spills
- Impacts of construction and operation on threatened or endangered species or their habitat.

The revised Resource Report 3 has four additional appendices:

- Appendix D – Drop camera video
- Appendix E – Ichthyoplankton entrainment estimates at the Broadwater FSRU facility based on data collection during the 2002 Poletti ichthyoplankton program
- Appendix G – Sediment deposition resulting from construction of a natural gas pipeline trench
- Appendix H – Natural backfilling of natural gas pipeline trench

#### **Resource Report 4 – Cultural Resources**

Resource Report 4 describes the regulatory requirements related to archaeological resources and consultations with Native American Groups. Authorization of the Project by FERC is conditional on Broadwater's compliance with the 1966 National Historic Preservation Act as amended in 1976, 1980, and 1992. The Area of Potential Effect (APE) is defined based on the potential for effect which may be different for aboveground resources (historic structures and landscapes) and subsurface resources (archaeological sites). The potential for impacting archaeological resources along the proposed 21.7 mile pipeline route is limited to the 300 foot (91 m) wide construction right-of-way for the pipeline trench and the 4,000 foot (1,219 m) right of way for the construction vessel anchors. The vertical APE within the pipeline's excavated trench is 8 feet (2.4 m). For the YMS tower, the APE is 230 feet (70 m) deep and encompasses approximately 13,180 square feet (1,225 m<sup>2</sup>).

Broadwater contacted seven Native American Groups in order to give them the opportunity to identify their concerns about properties of religious or cultural importance that may be affected by the Project. None have responded to date.

The general area of the Project contains 105 reported shipwrecks/obstructions, 18 of which have known locations. Four of these known locations fall within Broadwater's APE. In April and May, a remote-sensing geophysical survey was conducted over the APE and produced 13 anomalies which comprise nine discrete targets with moderate to high potential to be archaeological deposits. All nine of the targets are located within the temporary anchor construction right-of-way. Avoidance of these nine targets will be accomplished during construction through the use of midline buoys on anchor cables.

Examination of vibratory core data resulted in no physical evidence for the existence of archaeologically sensitive intact paleosols.

All known cultural resources in the APE will be avoided.

Resource Report 4 contains the following appendices:

- Agency and native American correspondence
- Unanticipated discovery plan
- Overview/survey report
- Proposed pipeline route survey

#### **Resource Report 5 – Socioeconomics**

Resource Report 5 provides a socioeconomic overview of the Project area and includes a description of the municipalities, population, income, labor force, housing, local public services and local government revenues and expenditures. It also addresses the socioeconomic impacts during the construction and operation phases of the Project and mitigations to address negative impacts.

The towns and villages proximate to the Project area are in Suffolk County, which encompasses the eastern two-thirds of Long Island and has a population of 1.4 million. All the municipalities profiled are within a 15- to 20-mile (24- to 32-km) radius of the proposed Project and could possibly be impacted during construction or operation of the Project. The list includes four towns (Brookhaven, Huntington, Riverhead and Smithtown) and eleven villages/cities (Asharoken, Belle Terre, Head of Harbor, Huntington Bay, Lloyd Harbor, Nissequogue, Northport, Old Field, PoQuott, Port Jefferson and Shoreham). The socioeconomic assessment considers the following issues:

- influx of temporary workers,
- land-based impacts associated with installation of the infrastructure, and
- fiscal impacts on local governments such as incremental revenues and expenditures.

Total socioeconomic impacts were estimated for both Suffolk County and New York State. Economic impacts were measured by assessing the direct expenditures of the Project's construction and operational phases on total industry output, employee compensation, and

employee levels. Confidential Project construction and operational costs have been omitted from Resource Report 5.

Broadwater expects the construction phase of the Project to take place during late 2009 and 2010. During the construction period, the impact on the regional economy will be short-term, driven by contractual-related spending on goods and services to support construction and installation of the Project. However, due to the highly specialized nature of the energy production equipment and civil works, only a portion of the total construction period capital expenditures will provide a long-term impact on the region's economy. The majority of the Project's capital cost components will likely be imported from international manufacturers and fabricators. Transportation impacts on local roads and main arteries are expected to be minimal. The local resources likely to be impacted by the Project construction would include fabricators, storage facilities, support vessels and tugboats, barges, and security support.

The total direct capital expenditures for marine pipeline construction anticipated to impact Suffolk County is \$11.1 million. The estimated 139 construction workers coming into the Project area will have a minor impact on the area's total labor force, employment level, and unemployment rate. Direct expenditures during the construction period will generate an economic impact totaling \$20 million for Suffolk County in 2010.<sup>1</sup> In addition, these expenditures would result in value added of \$8.9 million in 2010, including \$5.2 million in total employee compensation.<sup>2</sup>

The economic impacts during FSRU terminal operations are based on direct expenditures incurred in the Project area necessary to run and maintain the facility, such as personnel wages, facility maintenance, insurance, and bulk chemicals. The annual recurring expenditures will impact the host community over the years 2011 to 2040. The FSRU terminal will employ a total of 60 persons. The direct expenditures to support FSRU operations will generate a total of \$39.5 million per year economic impact for Suffolk County. The cumulative economic impact over the entire 30 year life of the Project is estimated to be \$475 million. The fiscal analysis in Resource Report 5 does not consider municipal payments in lieu of taxes which are potentially part of the financial structure of the Project and could have a significant positive impact on the host area's municipal fiscal position.

The estimated environmental benefits are based on fewer air pollutant emissions resulting from a New York State projected economic growth scenario, where relatively more natural gas is used to generate electric power. Public benefits from avoided air pollution damages could average \$181 million per year between 2011 and 2020.

Resource Report 5 contains the following appendices:

- Economic impacts of the proposed Broadwater Project

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<sup>1</sup> The economic impact affects the total value of production by industry for the calendar year that would result from the Project's construction expenditures.

<sup>2</sup> Value added is the sum of employee compensation, proprietor income, other property income, and indirect business tax.

- Estimated environmental benefits of the proposed Broadwater Project

## **Resource Report 6 – Geological Resources**

Resource Report 6 describes the physiography and geology of the Project area and the geological hazards, such as the seismicity, of the area.

Both the modified Mercali scale and the Richter scale are used to measure earthquake intensities. Mercali numbers do not correspond directly to Richter numbers so there is no conversion factor. Since 1900, only three earthquakes with magnitudes greater than 4.5 on the Richter scale or VI on the Mercali scale have occurred in the Long Island Sound area. According to the U.S. Geological Survey Earthquake Hazards program, an earthquake with a magnitude greater than 4.75 on the Richter scale has a 3-6% probability of occurring within 50 years in the Project area. This probability decreases significantly with higher Richter scale values. According to Resource Report 6 for the Eastchester Extension Project, pipelines are capable of withstanding earthquakes with an intensity of VII on the Mercali scale which is generally comparable to a range of 5.8-6.1 on the Richter scale. Based on this information, there is a low probability that an earthquake strong enough to damage the pipeline would occur during the life of the Project.

Installation of the mooring tower will require piles to be driven 230 ft beneath the seabed. This is not expected to have any impact on the geologic structure underlying Long Island Sound. A geotechnical investigation revealed that bedrock is not present near the surface and that blasting will not be required for installation of any portions of the pipeline. Broadwater will use concrete mats for pipeline protection wherever adequate burial depth cannot be achieved during construction.

There are no areas of paleontological significance in the Project area.

## **Resource Report 7 – Soils**

Since no land-based facility has been identified, Resource Report 7 describes the soil characteristics of the seafloor, construction impacts and mitigation measures. The seafloor in Long Island Sound consists of silt, clay, sand and gravel. Bedload transport of coarse-grained material, sorting and deposition of fine-grained material, sorting and reworking of sediments, and non-depositional erosion are the four major processes operating in the 850 square mile study area. Trenching operations will be conducted to reduce the amount of sediment introduced into the water column. An estimated total of 354,320 cubic yards and 2,600 acres will be impacted by construction of the proposed marine pipeline. A 4,000 foot trench across the Stratford Shoal may require dredging instead of subsea plowing due to the presence of competent material that could prevent plowing. Also, for safety reasons, subsea plowing will not be used to lower the FSRU and IGTS tie-ins or where the pipeline route traverses the AT&T and Cross Sound Cable. At cable crossings, divers and submersible pumps will be used to place concrete pads, which will be used to separate the pipeline and the other cable by a minimum of one foot.

Appendices included in Resource Report 6 consist of:

- VGS log of vibracores

- Cone penetrometer graphs

### **Resource Report 8 – Land Use, Recreation and Aesthetics**

Resource Report 8 describes onshore and offshore land uses including commercial and recreational fishing, recreational and aesthetic resources and the impact of the Project on these resources. It also addresses measures that need to be implemented to avoid and mitigate construction and operational effects.

The Project is located over nine miles from any shoreline. A visual resource assessment was conducted and includes determination of a radius of impact for the Project, an inventory of aesthetic resources within the radius of impact, photo simulations and potential mitigation measures.

During construction, 197 acres of seafloor will be disturbed as a result of the pipeline trench excavations, with an additional 3,174 acres being disturbed by construction barge anchor cable sweep. The yoke mooring system includes a stationary tower structure with a footprint of approximately 13,180 square feet (1,225 m<sup>2</sup>).

Navigational aids, including lights and foghorns, will be installed on the FSRU to warn other vessels in Long Island Sound, and navigational charts will be updated to show the location of the FSRU. There is no official vessel traffic routing system in the Sound, but the FSRU location is intended to be outside of commonly used East-West routes. Its current location was chosen to minimize impacts on commercial shipping, recreational boating and fishing.

The FSRU would be located in a high-use lobster fishery area. The near-shore shellfish industry will not be affected. During construction, affected areas will be closed to fishing. However, the effects on the fishery would be mitigated by scheduling construction for the winter months. Within the vicinity of the FRSU, up to five lobstermen could lose access to a portion of their historic fishing grounds.

Ferry lines in the area would be temporarily rerouted during pipeline construction. Pipeline construction is expected to proceed at the rate of 1 mile per day. Ferries and recreational vessels would be excluded from the safety zone around the FSRU and LNG carriers, as established by the USCG. The FSRU is not in the path of any existing ferry line.

The results of the Fishermen outreach are included as an appendix to Resource Report 8.

### **Resource Report 9 – Air and Noise Quality**

Resource Report 9 describes the existing air and noise quality and the relevant federal and New York State air regulations. It also addresses construction and operation air quality and noise impacts and mitigation.

Air emissions from the Project will be regulated under the Clean Air Act and state law administered by NYSDEC. The Project would be located within Suffolk County, New York, which is part of the New Jersey-New York-Connecticut Interstate Air Quality Control Region (AQCR). This AQCR is currently designated as an attainment area for CO, lead, NO<sub>2</sub>, PM<sub>10</sub> and

SO<sub>2</sub>. It is designated as a severe non-attainment area for the 1-hour ozone standard and as a moderate non-attainment area for the 8-hour ozone standard. Since most ozone at ground level is formed during reactions between NO<sub>x</sub> and VOCs, control programs for ozone regulate NO<sub>x</sub> and VOC emissions. Suffolk County is also designated as a non-attainment area for PM<sub>2.5</sub>. Non-attainment New Source Review in New York is delegated to NYSDEC and the Prevention of Significant Deterioration (PSD) review is conducted by EPA Region II.

The Broadwater Project will be evaluated against ambient air concentration thresholds for a Class II Area which allows a moderate increase over baseline air quality levels.

Pollutant emission limits and monitoring, reporting, and record-keeping requirements depend on the emission source type and size. The FSRU process heaters (four with one extra as back-up) are subject to Subpart Db of 40 CFR 60. The LNG storage tanks do not appear to be subject to the requirements of Subpart Kb of 40 CFR 60 because LNG would only be directly released to the atmosphere during emergency situations. The FSRU gas turbines (two and one back-up, 22 MW each) will be subject to the requirements of Subpart GG of 40 CFR 60. So far, the EPA has not made an agency-wide determination about whether an FSRU would be subject to a PSD threshold of 250 or 100 tons per year (tpy). The PSD threshold of 100 tpy applies to the gas turbines and process heaters separately. The estimated annual potential emissions for the FSRU as a whole and the Title V Major Source Size Thresholds are shown in Table A5-1.

**Table A5-1 – Potential Emissions and Major Source Thresholds**

	<b>FSRU Annual Emissions (tpy)</b>	<b>Title V Major Source (tpy)</b>
NO <sub>x</sub>	62	100/25
CO	89	100
VOCs <sup>3</sup>	18	50/25
PM <sub>10</sub>	48	100
PM <sub>2.5</sub>	48	100
SO <sub>2</sub>	4	100
Ammonia	66	--
Total HAPs	9.4	25

The emission estimates reflect the use of selective catalytic reduction (SCR) for NO<sub>x</sub> reduction and CO oxidation catalysts on the gas turbines and process heaters. The FSRU is not a major source of hazardous air pollutants (HAPs) and does not fall under National Emission Standards for HAPs regulations.

<sup>3</sup> The first value is the threshold for 8-hour moderate ozone nonattainment designation, second value is threshold for 1-hour severe ozone non-attainment designation.

Due to the transition from the 1-hour to the 8-hour ozone standard and new non-attainment designation, it is unclear which threshold will apply for NO<sub>x</sub> and VOC. If the 1-hour severe ozone non-attainment designation applies, the proposed Project will be above the major stationary source size for NO<sub>x</sub> and will require a Title V permit. Otherwise, the proposed project will be below the major stationary source size under Title V and will need to obtain a State Facility (minor source) permit from New York State.

Construction is anticipated to occur over a two-year period but only during the winter months. The major construction activities consist of pipeline installation, yoke mooring system tower installation, and FSRU towing. Construction-related emissions are not covered by an air permit program and are evaluated under the General Conformity rule. The NO<sub>x</sub> emissions are above the General Conformity *de minimis* threshold of 100 tpy for each year of construction and are subject to mitigation. However, with construction scheduled to occur outside the ozone season, Broadwater does not need to mitigate short-term ozone precursor emissions.

Emissions from vessel activities during normal FSRU operation are not covered by an air permit program but are evaluated under the General Conformity rule by comparison to *de minimis* thresholds.

**Table A5-2 – Vessel Emissions (tpy)**

	<b>LNG Carrier Unloading</b>	<b>Carrier Transit and Support Tugs</b>	<b>Total</b>	<b>Annual General Conformity <i>De minimis</i> (8-hour ozone)</b>
NO <sub>x</sub>	23	427	450	100
CO	2	54	56	NA
VOCs	4	18	22	50
PM <sub>10</sub> / PM <sub>2.5</sub>	33	25	58	100
SO <sub>2</sub>	245	341	586	NA
CO <sub>2</sub>	14,545	37,437	51,982	NA

Vessel activity results in annual NO<sub>x</sub> emissions above the *de minimis* threshold, therefore an evaluation of mitigation options will be required.

Atmospheric dispersion models were used to compare estimated air quality impacts from FSRU operations to existing conditions. Modeled air quality concentrations due to the FSRU are below Significant Impact Levels. Locations within an assumed 500 m safety zone around the FSRU were excluded from the Offshore Coastal Dispersion model.

There are no state-wide noise regulations in New York. However, a noise guidance document issued by NYSDEC can be used to evaluate a project’s potential noise impact. Ambient airborne noise levels over ocean areas are in the 50 to 55 dBA range. The predicted noise from the operation of the FSRU is 50 dBA at 0.9 mile (1,500 m) and therefore would not be noticeable 1 mile or more from the FSRU. However, at distances of less than 0.9 mile, the operating noise may become noticeable and at less than 820 ft (250 m), it may begin to interfere with normal conversation volume. At the boundary of a proposed 500 m safety zone, the level would be 59

dBa. In addition to normal FSRU operation, foghorns installed on each end of the FSRU will generate warning signals of 146 dBA at 3.3 ft (1 m) as required by USCG regulation which will be audible at 2 miles (3.2 km). This foghorn sound level will be barely audible on shore over background onshore noise levels.

During construction, there will be increased noise level which could impact recreational boaters in sailboats or other non-powered vessels. However, Broadwater states that it will not affect human receptors onshore and can be avoided by recreational boaters.

Appendices included in Resource Report 9 consist of:

- Construction emissions study
- Emissions calculations workbook
- Air quality modeling report

### **Revised Resource Report 10 – Alternatives**

Resource Report 10 describes the alternatives considered in the development of the Broadwater Project. Seven types of alternatives were considered: (i) the no action or postponed action alternatives, (ii) system alternatives to the project, (iii) LNG terminal alternatives, (iv) alternative LNG terminal sites, (v) pipeline route alternatives, (vi) LNG terminal equipment/technology alternatives, and (vii) pipeline construction alternatives.

#### *No action or postponed action alternatives*

Absent the Project, Broadwater states that the objectives of the Project would not be met, and a source of reliable, long-term, and competitively priced natural gas would not be available to the region. The impact, both economic and environmental, to the region of delaying the Project by 2-3 years in the hopes that another project might be built would involve higher energy prices, greater emissions, and greater natural gas price volatility.

Use of other fossil fuels would result in a decline in air quality. Traditional, domestic natural gas production levels are expected to continue production decline due to depletion. New sources of nuclear power or hydropower are unlikely to be sited in the region in the foreseeable future. Renewable sources of energy (wind, solar and biomass) and energy conservation are possible clean alternatives but it is unlikely that they will be available in sufficient quantities to meet the region's growing energy needs. The Long Island Offshore Wind Park and the Roosevelt Island Tidal Energy project are described as providing 140 MW and 10 MW of electric power, respectively.

#### *System alternatives*

Other existing or proposed LNG or natural gas facilities would have to meet the stated objectives of the Project: the capability to inject 1 Bcf/d into the greater New York metropolitan area market. Considering the existing pipeline infrastructure, the addition of 1 Bcf/d of incremental gas supply would constitute a significant system expansion for every pipeline except Iroquois. The average operating pressure on the Algonquin, Columbia, Tennessee and Transco pipelines is

low, ranging from 650 to 800 psi and could not accommodate the incremental volume requirements of the Project without looping. Even the Texas Eastern system, with a pressure of 1100 psi cannot meet the Project objectives without an expansion with substantial environmental impact. Furthermore, in order to meet Project objectives, all these pipelines would need access to incremental gas supply from interconnections either from the south or the north, which may not be sufficient for the future needs of the New York City / Long Island markets.

Broadwater examined all the approved onshore and offshore U.S. LNG terminals, most of which are located in the Gulf Coast. Although they represent new sources of natural gas supply, they are located far from the New York metropolitan region and would require significant expansion of the pipeline systems from the Gulf Coast. The only LNG terminal approved in the Northeast is the Weaver's Cove project in Fall River, Massachusetts, with a daily send-out capacity of 0.8 Bcf. If this terminal were built, significant additional pipeline infrastructure would be required to transport this new gas supply to the region via the Algonquin pipeline

Broadwater also examined the four proposed LNG terminals in the Northeast: KeySpan's LNG facility upgrade (0.5 Bcf/d) in Providence, Rhode Island, BP's Crown Landing project (1.2 Bcf/d) in New Jersey, and two offshore projects off the coast of Massachusetts, Northeast Gateway (0.8 Bcf/d) and Suez Neptune (0.4 Bcf/d). Broadwater concluded that the three proposed New England facilities are designed to serve the New England market and cannot meet the needs of the New York City / Long Island markets. BP's Crown Landing (1.2 Bcf/d) in New Jersey would require very costly downstream pipeline enhancements to provide incremental volumes to New York.

#### LNG terminal alternatives

Shell evaluated both the FSRU and GBS concepts. It was determined early on that the GBS option had more significant environmental and safety challenges because it had to be located in shallower water (up to 60 ft), which in Long Island Sound is closer to populated areas. Three onshore locations (Shoreham, Block Island and Plum Island) were evaluated and found to be environmentally less desirable than the proposed FSRU location.

Broadwater also evaluated shuttle regasification vessels (SRVs) and the number of separate SRV mooring / LNG transfer buoys that would be required to provide 1 bcf/d to the region. Broadwater estimated the maximum sea states during which LNG carrier berthing and LNG transfer / sendout operations could be accomplished and the frequency of these sea states in the Long Island Sound, Block Island Sound and Atlantic Ocean offshore of Long Island.

#### Alternative LNG terminal sites

Both the Atlantic Ocean and Block Island Sound were evaluated in addition to Long Island Sound for offshore locations. As a result of the comprehensive alternative LNG terminal site analysis, Broadwater identified 24 individual alternative facility concepts and site locations including: nine GBS sites, five, FSRU sites, eight land-based sites and two SRV sites (Figure A5-1). However, the sea conditions were considered too rough for routine and reliable unloading via side-by-side cargo transfer and a much longer gas pipeline would have to be constructed to carry the 1.0 Bcf/d to Iroquois. An offshore pipeline longer than 40 miles would

require intermediate pressure boosting located between the FSRU and the interconnection with the Iroquois pipeline. Within Long Island Sound, sites located close to the shoreline were eliminated due to their proximity to higher population densities and to sensitive marine resources and to avoid dredging issues.

#### Pipeline route alternatives

Broadwater examined several pipeline routes, onshore and offshore, that would reach the target market. One onshore route from an Atlantic Ocean LNG terminal located approximately 20 miles southeast of the Hamptons would make landfall east of Southampton and reach the existing Iroquois meter station at South Commack. Another offshore route from an Atlantic Ocean LNG terminal located approximately 20 miles southeast of Montauk Point would require two offshore platform based compressor stations and would have to be routed around Montauk Point, through Block Island Sound, through the Race and westward along the central axis of Long Island Sound to the Iroquois pipeline. These two Atlantic Ocean alternatives are less desirable than the proposed FSRU site in Long Island Sound because they would require significant new pipeline construction in order to connect to Iroquois.

#### LNG terminal equipment technology alternatives

Broadwater examined vaporization technology alternatives, mooring system alternatives, nitrogen supply alternatives and a ballast transfer system.

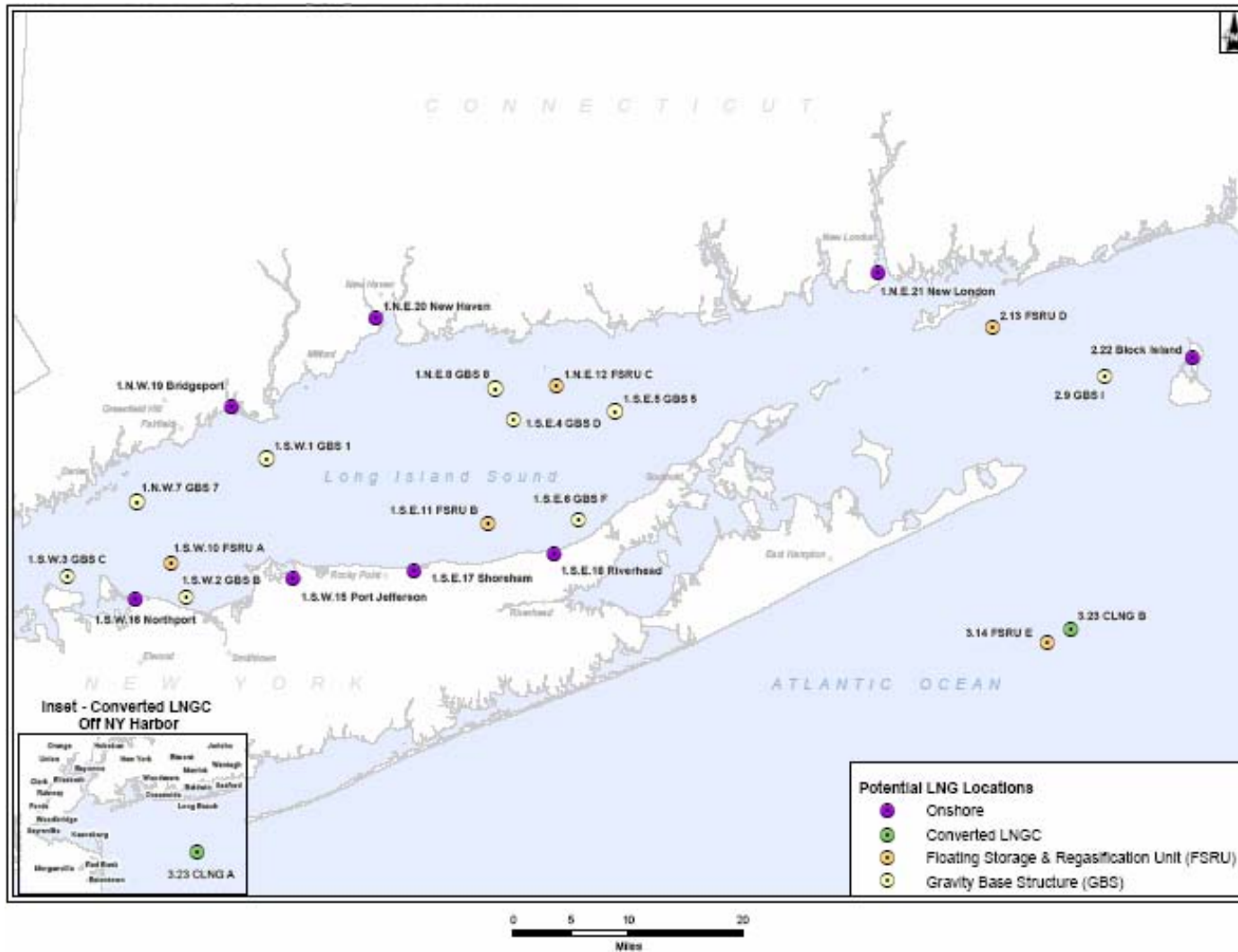
Four vaporization technologies were considered: SCV, STV, seawater-warmed vaporization and air-warmed vaporization. Both of the last two technologies would require standby technology for the colder months of the year when the air and water temperature is too low for the system to be effective on its own so they were eliminated from consideration. Based on evaluations of thermal efficiency, global efficiency, NO<sub>x</sub> emissions and CO<sub>2</sub> emissions, Broadwater selected STV with SCR, which allowed for the lowest achievable emissions rates at comparable thermal efficiencies.

Given the 90-ft water depths in Long Island Sound, there is really only one optimum mooring system, the yoke mooring system which is piled to the seabed. The alternative, an external turret system, is optimum for depths that are greater than 150 ft and requires 6 or more leg anchor systems.

Broadwater proposes to add nitrogen to the gasified LNG in order to meet the gas quality requirements of the Iroquois system. Two nitrogen injection technologies were evaluated: the cryogenic nitrogen plant and the membrane nitrogen plant. Since the cryogenic nitrogen plant is affected by motion, it is less suitable for a marine application than the membrane nitrogen plant.

In order to conserve ballast water, Broadwater assessed a ballast transfer system that would transfer water from the FSRU to the LNG carrier during LNG transfer operations. However, the system was not practical since LNG carriers are currently not configured to accept ballast water from another facility.

Figure A5-1 Potential LNG Sites Considered by Broadwater<sup>1</sup>



<sup>1</sup> Broadwater Resource Report 10.

### Pipeline construction alternatives

Broadwater evaluated both the conventional marine pipeline installation method and the dynamically positioned (DP) vessel marine pipeline installation method. Although using a DP laybarge would minimize bottom disturbance and damage to existing utility cables or pipelines, Broadwater did not consider it the preferred method because of cost, contractual, logistical, legal and labor considerations.

### **Onshore Resource Reports 1-12**

Temporary and permanent onshore facilities would be required during construction and operation. Broadwater proposes to use existing facilities to avoid or minimize additional environmental impact. Only a waterfront facility is required to support construction activities. The permanent leased onshore facilities would be located either in Greenport or Port Jefferson and would include office space and warehouses. The office space would include conference and training facilities as well as the emergency response and communications center. The warehousing with waterfront access would accommodate tugs, personnel transfer and materials transfer.

Resource Reports 5 (Socioeconomics), 10 (Alternatives), 12 (PCB Contamination) and 13 (Engineering Design and Materials) were not required for the onshore facilities.

### **Permits**

Table A5-3 and Table A5-4 list the federal and state permits, respectively, which Broadwater needs to acquire.

**Table A5-3 – List of Federal Permits, Approvals and Consultations**

<b>Agency</b>	<b>Act</b>	<b>Permit/Approval</b>
FERC	<ul style="list-style-type: none"> <li>• Natural Gas Act 15 U.S.C. 717 et seq., 18 CFR Part 153, Subpart B (2002)</li> </ul>	<ul style="list-style-type: none"> <li>• Sections 3 and 7 approvals to site, construct and operate the LNG terminal and to construct and operate the subsea connecting pipeline facilities, including the pipeline riser and mooring tower, respectively</li> </ul>
USCG	<ul style="list-style-type: none"> <li>• The Maritime Transportation Security Act of 2002</li> <li>• 33 CFR § 127</li> </ul>	<ul style="list-style-type: none"> <li>• Review process – project must be compatible with National and Area Marine Security Plans</li> <li>• Letter of Recommendation</li> </ul>
Advisory Council on Historic Preservation	<ul style="list-style-type: none"> <li>• National Historic Preservation Act, Section 106</li> </ul>	<ul style="list-style-type: none"> <li>• Review of project effects on cultural resources</li> </ul>
EPA	<ul style="list-style-type: none"> <li>• Clean Water Act, Section 401 and 404</li> <li>• Clean Air Act</li> </ul>	<ul style="list-style-type: none"> <li>• Review of Section applications</li> <li>• Prevention of Significant Deterioration, New Source Review</li> </ul>
NOAA Fisheries	<ul style="list-style-type: none"> <li>• Marine Mammal Protection Act, 16 U.S.C. 1361 et seq.</li> <li>• Magnuson-Stevens Fisheries Conservation and Management Act – Sustainable Fisheries Act</li> <li>• National Fishing Enhancement Act of 1984</li> </ul>	<ul style="list-style-type: none"> <li>• Consultation</li> <li>• Consultation regarding Essential Fish Habitat</li> <li>• Consultation regarding the National Artificial Reef Plan and commercial/recreational fisheries</li> </ul>
USACE	<ul style="list-style-type: none"> <li>• Clean Water Act (CWA), 33 U.S.C. § 1344 et seq.</li> <li>• Rivers and Harbors Act of 1899 33 U.S.C. § 403 et seq.</li> </ul>	<ul style="list-style-type: none"> <li>• Section 404 – dredge and fill permits</li> <li>• Section 10 permit</li> </ul>
USFWS	<ul style="list-style-type: none"> <li>• Marine Mammal Protection Act, 16 U.S.C. 1361 et seq.</li> </ul>	<ul style="list-style-type: none"> <li>• Consultation</li> </ul>

Agency	Act	Permit/Approval
Federal agencies	<ul style="list-style-type: none"> <li>• NEPA 42 U.S.C. § 4321 et seq., particularly 42 U.S.C. § 4332, 40 CFR Part 1500</li> </ul>	<ul style="list-style-type: none"> <li>• Procedural statute, not a permitting statute. Requires federal agencies to consider environmental impacts of proposed action</li> </ul>
Federal agencies consultation with USFWS and NOAA Fisheries	<ul style="list-style-type: none"> <li>• Section 7, Endangered Species Act, 16 U.S.C. 1531 et seq.</li> </ul>	<ul style="list-style-type: none"> <li>• Consultation regarding federally listed threatened or endangered species. If potential adverse impact identified, then a Biological Opinion must be issued by responsible agency. Primarily a procedural statute. No permit required unless an incidental take of protected species is involved (then Section 10 permit required)</li> </ul>
FAA	<ul style="list-style-type: none"> <li>• 49 CFR Part 77</li> </ul>	<ul style="list-style-type: none"> <li>• Review of construction or alteration that might affect navigable airspace</li> </ul>

**Table A5-4 – List of State Permits and Approvals**

<b>Agency</b>	<b>Act</b>	<b>Permit/Approval</b>
NYSDEC	<ul style="list-style-type: none"> <li>• Clean Water Act 33 U.S.C. § 1342(a) – delegated from EPA</li> <li>• Clean Water Act 33 U.S.C. § 1341</li> <li>• Clean Air Act Title V 40CFR 70 – delegated from EPA; implementing NYS regulations: 6 NYCRR 201</li> <li>• 6 NYCRR Part 596</li> </ul>	<ul style="list-style-type: none"> <li>• State Pollution Discharge Elimination System (SPDES) permit</li> <li>• Section 401 – State certification of water quality</li> <li>• Certificate to operate air contamination sources</li> <li>• Bulk Storage Permit</li> </ul>
NYSDOS	<ul style="list-style-type: none"> <li>• New York State Coastal Zone Management Act -delegated from the Federal DOC</li> </ul>	<ul style="list-style-type: none"> <li>• Coastal Zone Consistency Determination</li> </ul>
NYSDDS	<ul style="list-style-type: none"> <li>• Natural Gas Pipeline Safety Act, 49 U.S.C. §§ 60101, et seq. (2000) - as agent for USDOT OPS</li> </ul>	<ul style="list-style-type: none"> <li>• Requirement to certify that Broadwater will design, install, inspect, test, construct, operate, replace, and maintain a gas pipeline facility under the standards and plans for inspection and maintenance under section 60108 of 49 U.S.C. §60108.</li> </ul>
NYSOGS	<ul style="list-style-type: none"> <li>• New York Public Lands Law</li> </ul>	<ul style="list-style-type: none"> <li>• Submerged Lands easement/lease</li> </ul>
NYSOPRHP	<ul style="list-style-type: none"> <li>• Section 106, National Historic Preservation Act</li> </ul>	<ul style="list-style-type: none"> <li>• Review of project effects on cultural resources</li> </ul>

## APPENDIX 6

### DET NORSKE VERITAS: BROADWATER RESPONSE TO USCG LETTER (DATED DECEMBER 21, 2005)

DNV prepared Broadwater's response to the USCG's letter concerning the four issues related to the applicability of the Sandia Report to the site, the FSRU and future generations of LNG carriers. LAI reviewed DNV's analysis and highlighted the key points of the analysis.

#### **Issue #1: Breach sizes for FSRU and 250,000 m<sup>3</sup> LNG carriers compared to Sandia Report breach sizes**

Response: Larger "future generation" vessels like the FSRU and the 250,000 m<sup>3</sup> LNG carriers have thicker inner and outer hull plates and a larger horizontal distance between the outer and inner hulls compared to current LNG carriers. Specifically, current LNG vessels have 2.2 m between the inner and outer hull while the FSRU is expected to have 4.8 m between the hulls and a 216,000 m<sup>3</sup> vessel has 2.6 m between the hulls. A collision vulnerability analysis calculates the side impact energies that can be absorbed by different sized LNG carriers and the FSRU before tank shell deformation occurs. This analysis revealed that larger carriers absorb about twice the collision energy that smaller carriers are capable of absorbing. Since the more energy a carrier is able to absorb, the smaller the breach size, larger LNG carriers or the FSRU will experience smaller breach sizes given the same impact energies. Therefore, the Sandia Report breach sizes are conservatively applicable to the proposed Broadwater FSRU and larger LNG carriers.

#### **Issue #2: Spill volumes for FSRU and 250,000 m<sup>3</sup> LNG carriers compared to Sandia Report spill volumes**

Response: If a breach in the FSRU or LNG carrier is assumed to occur just above the water line, it will result in the largest LNG head, release the maximum volume of LNG and therefore produce the most conservative result. Specifically, the FSRU release volume will be 35,560 m<sup>3</sup> and the LNG carrier release volume will be 27,300 m<sup>3</sup> compared to the Sandia Report release volume of 12,500 m<sup>3</sup>.

#### **Issue #3: size of hazard zone for FSRU and 250,000 m<sup>3</sup> LNG carriers compared to Sandia Report hazard zones**

Response: The most serious hazard from an LNG spill is due to thermal radiation from a vapor cloud dispersion with late ignition because it has the potential of extending significantly longer than the thermal hazard zone from a pool fire. The size of the hazard zone is a function of five variables, including:

- hole size,
- LNG head above the breach,
- release rate,
- volume released, and

- weather conditions.

The Sandia report uses hole sizes of 1.12-1.60 m for accidental scenarios and a nominal credible hole size of 2.52 m for intentional spills. DNV’s most credible hole sizes for an accidental breach are 0.25 m, 0.75 m and 1.50 m.

The Sandia report models vapor dispersion distances with the CFD software VULCAN while DNV uses PHAST which is considered to give more conservative results. DNV extended the Sandia Report calculations to include the larger release volumes and higher LNG head discussed in Issue #2 while keeping the same hole sizes as the Sandia report. DNV also modeled vapor dispersion distances for three types of weather conditions:

- stability class F with wind speeds of 2 m/s,
- stability class D with wind speeds of 3.5 m/s, and
- stability class D with wind speeds of 7 m/s.

The most frequently occurring weather condition in Long Island Sound is D stability (49%) while F stability only occurs 15% of the time. Since there is limited mixing of the released gases under the stable conditions of the F stability class, they result in a greater hazard distance than any of the other weather conditions and are the most conservative result. DNV found that the Sandia distances to LFL are expanded when the larger spill volumes are used. Specifically, for the largest hole size of 2.52 m, the distance to LFL for a one tank FSRU spill increases to 3.32 km compared to its value of 2.45 km for the Sandia report.

The Sandia report also calculates distance to LFL for a three tank breach but the DNV report does not present the analogous result. The DNV report does not propose a hazard zone size based on the calculated distance to LFL.

**Issue #4: use of Long Island Sound atmospheric data instead of Maryland atmospheric data for calculation of vapor dispersion distances.**

Response: The Long Island Sound weather is summarized according to stability class and wind speed and it is found that stability class D is predominant. The three most common combinations of wind speed and stability class are shown in Table A6-1.

**Table A6-1 – Stability Class Conditions**

<b>Stability Class</b>	<b>Average Wind Speed</b>	<b>Percent of Day</b>
F	2 m/s	15%
D	3.5 m/s	49%
D	7 m/s	21%

These weather conditions were the ones used by DNV to model vapor dispersion distances in Issue #3. The Sandia report used a stability class of F and wind speed of 2.33 m/s.

## **Conclusions**

The Broadwater site specific consequence zones are larger than the Sandia hazard zones under the worst case stability F class conditions.

## APPENDIX 7

### DET NORSKE VERITAS FIRE MODELING

DNV provided site specific thermal hazard zones resulting from pool fires for the hole sizes defined by Sandia using the DNV software PHAST v6.42.

For the modeling, the FSRU tanks are assumed to be 98% full and the LNG carrier tanks 95% full. A breach in both the FSRU and LNG carrier is assumed to occur just above the water line and results in the largest LNG head and release volume. Sandia assumed that 50% of the tank volume would be released whereas DNV calculated the site specific release volumes based on the amount of draft. For the FSRU with a 44,850 m<sup>3</sup> tank the release volume is 35,560 m<sup>3</sup> whereas for the LNG carrier with a 42,000 m<sup>3</sup> tank the release volume is 27,300 m<sup>3</sup>. The DNV volumes are also larger than the Sandia release volumes because the Broadwater FSRU and LNG vessels are larger than the vessels used in the Sandia report. DNV used 1-2 m<sup>2</sup> accidental hole sizes and 5 m<sup>2</sup> intentional hole sizes just like the Sandia report. They also used the same discharge coefficient of 0.6 and the same surface emissive power of 220 kW/m<sup>2</sup>. However, DNV used a burning rate over water of 0.353 kg/m<sup>2</sup>/s while Sandia used 0.128 kg/m<sup>2</sup>/s. The burning rate of methane on land is known to be 0.141 kg/m<sup>2</sup>/s and 2.5 times greater over water. Furthermore, Sandia uses the same pool size for ignited pools and un-ignited pools while DNV calculates larger pool sizes for an un-ignited pool compared to an ignited pool.

The extent of personal injury due to thermal radiation is determined by the radiation exposure level, the duration of exposure and the type of personal protection. The distances to 5 kW/m<sup>2</sup> for both the DNV and Sandia results are summarized below.

**Table A7-1 – FSRU Pool Fire Modeling Results (Distance in m to 5 kW/m<sup>2</sup>)**

Hole Size	Sandia		DNV	
	F 2.33 m/s	F 2 m/s	D 3.5 m/s	D 7 m/s
0.5 m <sup>2</sup>		470	484	507
1 m <sup>2</sup>	554	606	629	655
2 m <sup>2</sup>	784	797	826	858
5 m <sup>2</sup>	1,305	1,127	1,167	1,211

**Table A7-2 – LNG Carrier Pool Fire Modeling Results (Distance in m to 5 kW/m<sup>2</sup>)**

Hole Size	Sandia		DNV	
	F 2.33 m/s	F 2 m/s	D 3.5 m/s	D 7 m/s
0.5 m <sup>2</sup>		466	482	504
1 m <sup>2</sup>	554	602	624	650
2 m <sup>2</sup>	784	791	820	852
5 m <sup>2</sup>	1,305	1,120	1,160	1,202

DNV does not find the effect of wind speeds and stability class to be significant. The duration of a pool fire depends on hole size, release rate, burning rate and volume released. Hole size is a significant variable; doubling the hole size will double the calculated distance to 5 kW/m<sup>2</sup>. The duration of the above pool fires are expected to be about 15 min for the 5 m<sup>2</sup> hole and 1.5 hours for the 0.5 m<sup>2</sup> hole.

DNV repeated their calculations with Sandia's lower burning rate and found an increase in hazard distances compared to the base case due to the larger steady state pools that will form with a lower burning rate. The FSRU pool fire distances to 5 kW/m<sup>2</sup> calculated by DNV range from 689 m to 1,344 m compared to 554 to 1,305 in the Sandia report for the same hole sizes. The LNG carrier pool fire distances to 5 kW/m<sup>2</sup> calculated by DNV range from 684 m to 1,335 m compared to 554 to 1,305 in the Sandia report for the same hole sizes.

## APPENDIX 8

### LIST OF FERC INTERVENERS

Intervener	Filing Date
The County of Suffolk, New York	2/17/2006 Supplemented on 3/9/2006
State of Connecticut Department of Environmental Protection	2/27/2006
State of Connecticut Attorney General	3/1/2006
State of Connecticut (Representatives of the Long Island Sound LNG Task Force)	3/2/2006
PSEG Energy Resources & Trade, LLC	3/6/6
BP Energy Company	3/6/6
Shell NA LNG LLC	3/8/2006
Town of Riverhead, New York	3/8/2006
New England LDCs (Including: Bay State Gas Company; Connecticut Natural Gas Corporation; New England Gas Company; Northern Utilities, Inc.; City of Norwich, Department of Public Utilities; NSTAR Gas Company; The Southern Connecticut Gas Company; and Yankee Gas Services Company)	3/9/2006
Dominion Cove Point, LNG, LP	3/9/2006
American Gas Association	3/9/2006
KeySpan Delivery Companies (Including: KeySpan Energy NY, KeySpan Energy LI and KeySpan Energy NE)	3/10/2006 Revised on 3/13/2006
Weaver's Cove Energy, LLC	3/10/2006
Town of Brookhaven, New York	3/10/2006 (electronic) 3/13/2006 (hard copy)
Coral Energy Resources, L.P.	3/10/2006
Town of Southold, New York	3/10/2006 Amended on 3/10/2006
Long Island Power Authority	3/10/2006
Town of Huntington, New York	3/10/2006 (electronic) 3/13/2006 (hard copy)
Consolidated Edison Company of New York, Inc.	3/10/2006

<b>Intervener</b>	<b>Filing Date</b>
Iroquois Gas Transmission System, L.P.	3/10/2006
	3/10/2006
Connecticut Fund for the Environment / Save the Sound	Resubmitted on 3/14/2006
New York State Public Service Commission	3/10/2006
Town of East Hampton, New York	11/22/2006
Cross-Sound Cable Company, LLC	1/23/2007