FERC Pre-Filing Review
Draft Resource Report 10 – Alternatives
AES Sparrows Point LNG Terminal & Mid-Atlantic Express Pipeline

Submitted October 2006

SUMMARY OF REQUIRED FERC REPORT INFORMATION		
TOPIC	**FERC Reference**	**Report Reference or Not Applicable**
1. Address the "no action" alternative. • Discuss the costs and benefits associated with the alternative.	§ 380.12(l)(1)	Section 10.3
2. For large Projects, address the effect of energy conservation or energy alternatives to the Project.	§ 380.12(l)(1)	Section 10.3.1 and 10.3.2, respectively
3. Identify system alternatives considered during the identification of the Project and provide the rationale for rejecting each alternative. • Discuss the costs and benefits associated with each alternative	§ 380.12(l)(1)	Section 10.4 and 10.5
4. Identify major and minor route alternatives considered to avoid impact on sensitive environmental areas (e.g., wetlands, parks, or residences) and provide sufficient comparative data to justify the selection of the proposed route. • For onshore projects near to offshore areas, be sure to address alternatives using offshore routings.	§ 380.12(l)(3)	Section 10.6
5. Identify alternative sites considered for the location of major new aboveground facilities and provide sufficient comparative data to justify the selection of the proposed site.	§ 380.12(l)(3)	Section 10.5

TABLE OF CONTENTS

LIST OF APPENDICES

LIST OF TABLES

LIST OF FIGURES

10. ALTERNATIVES

10.1 Introduction

10.1.1 Project Description

AES Sparrows Point LNG, LLC (Sparrows Point LNG) proposes to construct, own, and operate a new liquefied natural gas (LNG) import, storage, and regasification terminal (LNG Terminal) at the Sparrows Point Industrial Complex situated on the Sparrows Point peninsula east of the Port of Baltimore in Maryland. LNG will be delivered to the LNG Terminal via ship, offloaded from the ship to shoreside storage tanks, regasified on the LNG Terminal site (Terminal Site), and transported to consumers via pipeline. The LNG Terminal will have a regasification capacity of 1.5 billion standard cubic feet of natural gas per day (bscfd), with potential to expand to 2.25 bscfd. Regasified natural gas will be delivered to markets in the Mid-Atlantic Region and northern portions of the South Atlantic Region through an approximately 87-mile, 30-inch outside diameter natural gas pipeline (Pipeline) to be constructed and operated by Mid-Atlantic Express, LLC (Mid-Atlantic Express). The Pipeline will extend from the LNG Terminal to interconnections with existing natural gas pipeline systems near Eagle, Pennsylvania. Together the LNG Terminal and Pipeline projects are referred to as the Sparrows Point Project or Project. Both Sparrows Point LNG and Mid-Atlantic Express (hereinafter collectively referred to as AES) are subsidiaries of The AES Corporation.

The Project footprint is located in the counties of Baltimore, Harford, and Cecil in Maryland and the counties of Lancaster and Chester in Pennsylvania. The Terminal Site, which is located entirely within Baltimore County, is a parcel located within a former shipyard. The route proposed for the Pipeline (Pipeline Route), which crosses all of the listed counties, comprises industrial, commercial, agricultural, and residential lands. Together, the Terminal Site and the Pipeline Route comprise the Project Area.

As described in Section 1.10 of Draft Resource Report 1, *General Project Description* submitted to the Federal Energy Regulatory Commission (Commission) on September 27, 2006, The AES Corporation is considering the possibility of building a combined cycle cogeneration power plant (Power Plant) on the Terminal Site. The Power Plant would be configured with one F-Class combustion gas turbine, one steam turbine, and associated auxiliaries. It would operate only on natural gas and would produce approximately 300 MW of clean electric power within an area of high energy demand. The Power Plant would be connected to the local utility electric system via an overhead transmission line.

10.1.2 Energy Need

AES is proposing the Project in an effort to introduce a new incremental supply of natural gas into the Mid-Atlantic Region, which includes the Baltimore and Maryland area markets and certain parts of the (northern) portion of the South-Atlantic Region (through displacement rather than direct supply), to help serve the growing demand for energy in those markets in a safe, reliable, and economic manner.[1] The new incremental supply will initially be sized at 1.5 bscfd with potential expansion to 2.25 bscfd. The Project will provide access to natural gas production centers throughout the world without the need to construct new long-haul pipelines or expand the existing long-haul interstate pipeline systems that

[1] More specific information on the markets to be served and energy needs of the region may be found below and in Resource Report 1 – *General Project Description.*

currently serve the Mid-Atlantic Region.[2] The Project will also introduce new natural gas storage facilities into the Mid-Atlantic Region.

Energy demand in the United States continues to grow at a relatively constant pace. According to the U.S. Energy Information Administration (EIA 2006), total energy consumption in the United States is projected to increase by 27 percent by the year 2025 (1.2 percent annually), from 100 quadrillion British thermal units (Btu)/year in 2004 to 127 quadrillion Btu/year in 2025 (EIA, 2005). The EIA predicts that the projected growth in energy demand (from present to 2025) will vary by fuel type. Demand for coal and petroleum is expected to increase, with coal showing a steep increase in the years beyond 2020. Demand for natural gas will continue with strong growth through to 2020, after which it is expected to level off.

Most importantly, natural gas has increasingly become the fuel of choice in the United States. According to the EIA (EIA 2005), there are a number of underlying conditions that characterize the U.S. gas market, including:

- Increased gas demand driven by 200 gigawatts of installed gas-fired generation investment since 1999, with limited amounts of alternative fuel capability;
- Declines in domestic gas production throughout the lower 48 states and in offshore areas that are under the control of the United States;
- Increased gas imports from Canada nearing current maximum capacity;
- Decreased gas supply deliverability in the current transportation infrastructure;
- Declines in the demand destruction that began during the sustained high price environment; and
- Stabilization of gas demand due to the rebound in the U.S. economy beginning in 2003.

These conditions have led to supply constraints and a steadily increasing gas price floor, well above pre-2000 historical levels of below $3.00/thousand cubic feet (mcf) gas. The North American natural gas industry is facing a critical period over the next ten to 15 years where increased supply availability will be essential. Failure to increase supply to domestic markets will inevitably lead to sustained and higher prices unless new sources of natural gas supply, including LNG, are developed and delivered to the market via import terminals and associated pipeline facilities.

The need for incremental sources of natural gas supply to meet growing demand is particularly acute in the Mid-Atlantic and surrounding regions of the United States due to the distance from existing production areas and limited pipeline capacity from those production areas. The Sparrows Point Project will provide incremental gas supply directly into this area of acute need. The Mid-Atlantic Region consists of the southern parts of New York, as well as New Jersey, Pennsylvania, Maryland, Delaware, the District of Columbia and the northern parts of Virginia. Baltimore is within the Mid-Atlantic Region and will receive the benefits associated with the incremental source of natural gas either through direct supply or displacement. The northern portions of the South-Atlantic Region that will also benefit from the incremental source of natural gas from the Project include the southern parts of Virginia and the

[2] Access to natural gas reserves from production areas outside of North America throughout the world by conventional pipeline is not practical. The nearest non-North American production areas are thousands of miles from the Mid-Atlantic Region, and are separated from the United States by large bodies of water.

northern parts of North Carolina. The benefits in the northern portions of the South-Atlantic Region will be realized primarily through displacement rather than direct supply.

Natural gas demand for the Mid-Atlantic Region, which is the area that will be most directly served by the Project, was approximately 2.4 trillion cubic feet (Tcf) in 2005, representing approximately 11 percent of total U.S. natural gas consumption. Natural gas demand for the Mid-Atlantic Region has remained between 2.3 Tcf and 2.5 Tcf over the last ten years (i.e., 1995 to 2005), as shown on Figure 1.2-2 of Resource Report 1 - *General Project Description* . The EIA is projecting an approximate 1.3 percent compounded annual growth rate in natural gas demand for the Mid-Atlantic Region from 2005 to 2020, which results in an increase from 2.4 Tcf in 2005 to 2.9 Tcf in 2020. For the period between 2020 and 2030, EIA has forecasted a modest decline in natural gas demand to 2.8 Tcf in 2030. Natural gas demand from the electric power generation and commercial segments has shown the most growth for the period 1995 to 2005. As shown in Figure 1.2-4 of Resource Report 1 – General *Project Description*, EIA projects that natural gas demand from electric power generation will continue to show the most significant growth for the period 2005 to 2030.

Due to its location in the heart of an area of high (and increasing) natural gas demand, the Project will be a more efficient supplier of gas to its target markets than gas supplies from the Gulf of Mexico or other regions of production that would require significant pipeline expansion to provide the equivalent amount of natural gas to this market. Introduction of a new source of supply will have the effect of reducing the "basis" in the market intended to be served by the Project.[3] The Project will serve a need for additional natural gas by providing a new supply of LNG. While the LNG supplier will dictate many of the terms of delivery, natural gas will be supplied directly into the market area avoiding increasingly constrained pipeline capacities and the cost of transportation (as determined by the relevant tariffs) from the Gulf of Mexico or other regions of production. AES expects the LNG delivered to the LNG Terminal will be priced at various market index price points, thus being competitively priced with alternative supplies at these points.

10.2 Objective and Applicability

The Project has undergone an analysis with respect to both need and routing that considered both environmental and non-environmental factors. In developing the Sparrows Point Project, AES has considered several alternatives to the proposed LNG Terminal and Pipeline, including the no action alternative, energy alternatives (including conservation), and system alternatives (including LNG terminal alternatives and pipeline system alternatives). LNG Terminal location alternatives, Pipeline Route alternatives (as well as alternative location and design of aboveground facilities associated with the Pipeline), and LNG Terminal design alternatives (including alternative methods for dredged material disposal associated with the LNG Terminal marine works) were also evaluated. Each of these alternatives is discussed in further detail in this Resource Report.

This Resource Report is divided into six sections. Section 10.3 describes the no-action alternative. Because demand for energy in the Mid-Atlantic Region is predicted to increase, analysis of the no-action alternative necessarily involves a review of other means, including conservation, to meet the growing energy demands. System alternatives (i.e., alternatives to the proposed action that would make use of other existing or proposed LNG or natural gas facilities to meet the objectives of the Project) are

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[3] "Basis" refers to the differential between index prices for delivered gas in a given market and the Henry Hub prices of natural gas.

evaluated in Section 10.4. Section 10.5 evaluates aboveground site alternatives. Section 10.6 discusses alternatives to the proposed Pipeline, including different delivery points or delivery methods for the LNG upon its receipt at the LNG Terminal and alternatives to the proposed Pipeline Route. Section 10.7 provides an alternatives summary analysis. Section 10.8 provides a list of references used in the preparation of this Resource Report.

10.3 No-Action Alternative

As noted above, total energy consumption in the United States is projected to increase by 27 percent (1.2 percent annually) by the year 2025, from 100 quadrillion British thermal units (Btu)/year in 2004 to 127 quadrillion Btu/year in 2025.[4] The North American natural gas industry is facing a critical period where increased supply availability will be essential to meeting a large portion of the increase in total energy consumption that is expected. Natural gas demand will widen the gap between that demand and available supplies unless new sources of natural gas supply, including LNG, are developed and delivered to the market. Delivery of natural gas via import terminals and associated pipeline facilities is a safe and economical method to meet a significant portion of the anticipated growth in natural gas demand.

The no action alternative involves consideration of the potential benefits and adverse impacts if the proposed Project were not approved and constructed. If the Project were not constructed, the potential direct environmental impacts associated with construction and operation of the Project would not occur. However, the primary purpose of the Project, i.e., introduction of a new incremental supply of natural gas into the Mid-Atlantic Region that can be sourced from numerous world-wide production centers, would not be met. Accordingly, customers in those markets would have available fewer and potentially more expensive options for obtaining natural gas supplies in the near future. Options available for bringing additional natural gas to the Mid-Atlantic Region involve (i) construction of new LNG terminals (or construction of LNG terminal expansions) and associated expansions of pipeline capacities from outside the Mid-Atlantic Region[5] or (ii) increased production from sources outside the Mid-Atlantic Region and associated pipeline expansions.[6] Both of these options carry with them segmented tariffs associated with the delivery of gas to the Mid-Atlantic Region. These segmented charges are based on delivery areas throughout the interstate pipeline system; the tariff increases by segment the further away from the source where it is to be delivered. Assuming the gas is shipped from world production centers to either a LNG terminal outside the Mid-Atlantic Region or to the LNG Terminal proposed by AES at the same delivered cost, with transportation charges included, the delivered cost of gas from areas outside the Mid-Atlantic Region to customers inside the Mid-Atlantic Region would be higher than if it were to be delivered by the Project.[7] This same reasoning applies to new production sources (i.e., non-LNG) outside the Mid-Atlantic Region if one assumes that the market sets the price for both LNG and non-LNG sources of supply. Further, by introducing a new source of natural gas into the Mid-Atlantic Region competition

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[4] A significant portion of the expected total energy demand will be met with use of natural gas as an energy source. See discussion in Section 10.3.1 below. Expected contributions from other energy sources are noted in Section 10.3.2.
[5] As noted in Section 10.4.1.1, recently approved LNG import projects in the Mid-Atlantic Region (i.e., the Cove Pont expansion and the Crown Landing Project) meet only a portion of the expected demand in the area. No other import projects are proposed in the Mid-Atlantic Region at this time.
[6] Section 10.4.2.1 discusses the capacity constraints of existing pipelines currently serving the Mid-Atlantic Region.
[7] Shipping distances from Atlantic Basin LNG suppliers to the Project, however, are shorter than to the terminals in the Gulf States Region. This fact increases the likelihood that the all-in delivered cost of LNG to the Project will be less than the all-in delivered cost of LNG to terminals in the Gulf.

will be enhanced. In general, with all other factors being equal, increased supply competition has the effect of stabilizing or decreasing prices.

The no-action alternative would require that the unsatisfied demand for energy supply in the Mid-Atlantic Region be met through energy conservation if not by some other energy alternative (e.g., increased pipeline transmission capacity from areas of the United States (or North America) where natural gas supplies are more readily available. As described below in Sections 10.3.1 and 10.3.2 demonstrate that energy conservation and the use of alternative energy strategies, respectively, will not fully satisfy the market needs of targeted consumers.

10.3.1 Energy Conservation

AES evaluated the feasibility of using energy conservation measures as an alternative to the proposed Project.

According to a Report of the National Petroleum Council, titled *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, dated September 25, 2003, while conservation measures are aiding in reducing demand for natural gas, reductions possible through conservation measures are not anticipated to meet total energy demand. Conservation methods are neither uniformly mandated nor followed. Current energy conservation efforts, including the ENERGY STAR program, which is a joint effort between the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE) that identifies cost effective, energy efficient products that are designed to save customers money, reduce energy consumption and help protect the environment (EPA, 1999), will aid in reducing the amount of natural gas used in the production of a dollar's worth of economic output; however, conservation does not negate the need for the Project. These findings are supported by a report issued by the American Council for an Energy Efficient Economy (ACEEE) in 2003 cited within the Final Environmental Impact Statement on the Crown Landing LNG and Logan Lateral projects (FERC Docket Nos. CP04-411-000 and CP04-416-000), that analyzed projected energy demands in the Northeast, which includes New York, New Jersey, Pennsylvania, Delaware, and Maryland (ACEEE 2003). The ACEEE concluded that energy efficiency and renewable energy measures could result in a 0.9 percent reduction by 2008 in natural gas consumption in the northeastern states, which would not meet the approximate 1.3 percent compounded annual growth rate in natural gas demand for the Mid-Atlantic Region. The ACEEE recognized that energy efficiency and renewable energy are not the only policy solutions required to address the future natural gas needs of the United States, and that additional sources of natural gas will be required either from domestic sources or through the importation of LNG. Based on the projected increase in demand for natural gas within the Mid-Atlantic Region through the year 2030, AES has determined that energy conservation measures alone, coupled with the fact that these measures are not uniformly mandated, would not provide a sufficient alternative to the Project.

10.3.2 Energy Alternatives

AES evaluated the feasibility of using alternative sources of energy to satisfy the need intended to be served by the Project, such as the use of other fossil fuels, windpower generation, hydropower generation, and nuclear power. The use of these energy alternatives, whether alone or in combination, is not anticipated to provide a commercially viable and environmentally preferable alternative to the Project.

Several alternatives for meeting energy needs are available in the Mid-Atlantic Region; however, none is projected to be both as cost efficient and environmentally benign as natural gas. Other fossil fuels, specifically fuel oil and coal, are short term viable alternatives to meet the growing demand for energy in the region the greatest part of which is associated with electricity production. Compared to fuel oil or coal, natural gas is a relatively clean and efficient fuel that can reduce relative impacts on air quality (e.g., reduce emissions of nitrogen oxides, sulfur dioxide, particulate matter, and carbon dioxide) to generate the same amount of electricity. According to the Final Environmental Impact Statement prepared for the Crown Landing LNG project, because there is no pipeline infrastructure in place to distribute these fuels to market in the Mid-Atlantic Region, use of these alternative fossil fuels would require more truck, barge, and train trips to make up for the distribution of an equivalent amount of natural gas, which would increase air emissions and traffic congestion. The burning of coal would also require disposal of the resulting ash. Moreover, the recently passed Maryland Healthy Air Act, which mandates reductions in carbon dioxide (10 percent cut by 2018), sulfur dioxide (83 percent cut by 2010 and 90 percent by 2015), nitrogen oxides (67 percent cut by 2010 and 80 percent by 2015), and mercury (90 percent cut by 2010), may be seen to strongly recommend the use of natural gas for power production over coal sources as natural gas plants typically emit 43.7 percent less carbon dioxide, 99.6 percent less sulfur dioxide, 79.8 percent less nitrogen oxide, 99.7 percent less particulates, and 100 percent less mercury than coal plants. Natural gas plants also produce significantly fewer emissions than oil plants (EIA, Natural Gas Issues and Trends 1998).

The contribution of renewable fuels to U.S. electricity supply mix remains relatively small in the EIA's Annual Energy outlook for 2006. Although conventional hydropower remains the largest source of renewable generation through 2030, a lack of untapped large-scale sites, coupled with environmental concerns, limits its growth, and its share of total generation falls from 6.8 percent in 2004 to 5.1 percent in 2030 (EIA, 2006). See also the ACEEE Report.

While wind generation will be among the leaders in renewable energy generation, the anticipated expansion over current capacity will only increase by a modest 0.4 percent of total generation in 2004 to 1.1 percent in 2030 (EIA, 2006). Energy from wind power, while important to the overall energy mix, is not projected to grow significantly to be a commercially viable alternative to the Project. See also ACEEE Report.

Energy from nuclear power is not a commercially viable substitute able to replace or significantly offset the demand for natural gas over the next 20 years (EIA, 2006). The EIA reports that even with modest increases in nuclear generation from improvements in plant performance and expansion of existing facilities, the share of generation from nuclear plants declines from 20 percent in 2004 to 15 percent in 2030, as total generation grows at a faster rate than nuclear generation. Furthermore, nuclear power energy involves it's own distinct and significant environmental issues such as the disposal of radioactive materials (spent fuel), alterations to hydrological/biological systems, and visual impacts[8]

[8] FERC Final Environmental Impact Statement on the Crown Landing and Logan Lateral Projects, April 24, 2004, FERC Docket Nos. CP04-411-000 and CP04-416-000.

10.4 System Alternatives

AES evaluated potential system alternatives to the proposed action to determine whether existing LNG projects or LNG projects (both expansions and new construction) that have recently been approved by the Commission would meet the stated objectives of the proposed Project. Next, AES evaluated potential system alternatives to the proposed action to determine whether existing or new natural gas pipeline systems would meet the stated objectives of the proposed Project. Based on the conclusions set forth below, none of these system alternatives would meet the stated objectives of the proposed Project.

The basis for evaluation of system alternatives derives from information supplied by the EIA and other sources referenced below. The EIA has indicated (*see*, *e.g.*, Annual Energy Outlook - 2006) that the overall United States natural gas demand, as well as the natural gas market in the Mid-Atlantic Region, currently is supplied with natural gas from three main sources, including gas produced in the United States, imports from Canada, and LNG imports. The Mid-Atlantic Region receives gas produced in the United States and Canada through the existing interstate pipeline network. Production areas in the United States that serve the Mid-Atlantic Region are found primarily in the Gulf Coast (onshore and offshore) and, to a much smaller degree, in the Northeast. Both of these supply basins are expected to decline in the immediate future. For example, by 2010, domestic supplies available to the Mid-Atlantic Region are expected to decline by four percent, while gas available from Canada is expected to decline by 19 percent. Combining forecasted declines in supply basin deliveries with expected increases in demand, the total natural gas needs in the Mid-Atlantic Region are expected to increase by approximately 1.98 bscfd by 2010, 3.03 bcsfd028 bscfd by 2015, and 8.5546 bscfd by 2030. The report prepared by Concentric Energy Advisors (CEA) included in Attachment A (Table III-2) provides further information regarding these forecasted declines.

10.4.1 LNG Terminal Alternatives

In order to bridge the gap between declines of existing supplies and increases in demand, LNG imports are predicted to increase significantly. Specifically, the LNG component of the national supply mix is predicted to increase from 0.6 Tcf of the total United States demand in 2005 (approximately three percent of the total 20 Tcf demand) to 4.4 Tcf of the total United States demand in 2030 (approximately 16 percent of the total demand for natural gas in the United States) (EIA, The Annual Energy Outlook 2006). Currently, the Mid-Atlantic Region receives vaporized LNG from the existing Dominion Cove Point LNG terminal in Calvert County, Maryland (all of the LNG imported at Cove Point is consumed in the Mid-Atlantic Region) and significantly lesser amounts from the existing LNG import terminals located in Lake Charles, Louisiana and Elba Island, Georgia.

Recognizing the need to increase the supply of LNG within the country, the Commission recently approved applications to expand or construct 17 LNG import facilities, which, if all are brought on line, would increase United States LNG-import vaporization capacity initially by up to 16.0 bscfd. In addition to these approved projects (both new and expansion), there are numerous projects that have been proposed in various locations. These new and proposed facilities are described below. Because the majority of the approvals are not in the Mid-Atlantic Region and are constrained by capacity-limited interstate pipeline systems into the region, none of the newly approved terminals, including approved terminal expansions, nor any of the proposed terminals are capable of meeting the stated Project objective of introducing a new 1.5 bscfd (expandable to 2.25 bscfd) source of natural gas into the Mid-Atlantic Region.[9]

10.4.1.1 New LNG Terminals

Recently, the Commission and the USCG have authorized the construction and operation of 13 new LNG import terminals and related facilities as described below:

Port Pelican Offshore Deepwater Port Project – (USCG Docket No. 14134) Chevron Texaco is authorized to construct the Port Pelican Offshore Deepwater Port in the Gulf of Mexico offshore of Louisiana. The terminal would have the capability to store up to 330,000 cubic meters (m^3) of natural gas and have a send-out capability of an average of 1.6 bscfd. While U.S. Coast Guard (USCG) and DOT approvals were issued in November 2003, the project has been placed on hold indefinitely.

Gulf Landing Offshore Deepwater Port Project – (USCG Docket No. 16860) Chevron Texaco is authorized to construct the Gulf Landing Offshore Deepwater Port in the Gulf of Mexico offshore of Louisiana. The terminal would have the capability to store up to 200,000 cum of natural gas and have a send-out capability of an average of 1.0 bscfd. The USCG and DOT approvals were issued in February 2005.

Creole Trail LNG & Creole Trail Pipeline – (Docket Nos. CP05-360-000; CP05-357-000; CP05-357-001; CP05-357-002; CP05-358 and CP05-359) Chimaera's Creole Trail LNG is authorized to site, construct and operate a new LNG import terminal in Cameron Parish, Louisiana. The terminal would include four LNG storage tanks that would have the capability to store up to 640,000 m^3 of natural gas and have a send-out capability of an average of 3.3 bscfd. The Commission authorized Chimaera's Creole Trail Pipeline to construct and operate 116.8 miles of dual 42-inch diameter pipeline from the outlet of Creole Trail's proposed LNG terminal through Cameron, Calcasieu, Beauregard, Jefferson Davis, Allen and Acadia Parishes, Louisiana, to interconnect with markets throughout the United States through existing interstate pipelines.

Port Arthur LNG and Port Arthur Pipeline – (Docket Nos. CP05-83; CP05-84; CP05-85; and CP05-86) The Commission granted Samara's Port Arthur LNG authority to site, construct and operate a new terminal and related facilities near Port Arthur, Texas. The facilities include six LNG storage tanks with a nominal capacity of 160,000 m^3 each. The project would be constructed in two phases and would ultimately provide an average of three bscfd to existing interstate pipeline systems in Texas and Louisiana, connecting to markets in the Midwest and Northeast. Port Arthur Pipeline may construct and operate a new 70-mile, 36-inch diameter pipeline from the LNG terminal to an interstate interconnection. The Commission also authorized the company to construct and operate a three-mile, intrastate pipeline from the LNG terminal to an interstate interconnection with facilities owned by Natural Gas Pipeline Company (NGPL) in Jefferson County, Texas.

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[9] The Final Environmental Impact Statement on the Crown Landing LNG and Logan Lateral Projects (FERC Docket Nos. CP04-411-000 and CP04-416-000) correctly notes that, "[f]rom a commercial perspective, the best location of an LNG terminal is close to the market it is intended to serve." The great distance from terminals in the Gulf of Mexico Region "effectively limits them from serving the Mid-Atlantic market."

Crown Landing LNG Project – (Docket No. CP04-411) Crown Landing LLC, a wholly owned subsidiary of BP America Production Company, proposes to construct and operate a new onshore LNG import terminal in Logan Township, New Jersey. The proposed terminal would store up to 450,000 m^3 of LNG equivalent to 9.2 bscfd of gas, vaporize LNG and send it out through a connecting pipeline at a base load rate of 1.2 bscfd. The entire capacity of the Crown Landing project is committed for the next 20 years (Crown Landing FEIS 2006). The project would interconnect with a new 11-mile pipeline that the Commission also approved. The pipeline would be constructed by Texas Eastern Transmission Company (TETCO) (Docket No. CP04-416), and would extend from the terminal through Delaware County, Pennsylvania, to transport the vaporized LNG to various markets in the United States. Crown Landing and TETCO also anticipate interconnections with facilities operated by Transco and Columbia Gas Transmission Company (Columbia). Crown Landing hopes to begin service from the facility in late-2008. Operational service by 2008 is dependent upon a favorable decision by the United States Supreme Court concerning a challenge by the State of Delaware as to the jurisdiction of Delaware or New Jersey over certain improvements appurtenant to the New Jersey shore of the Delaware River. A special master was appointed on January 23, 2006 to hear testimony in the proceeding. There is no timetable for resolution of the challenge, and the outcome is uncertain.

Even if the Supreme Court rules in a manner that allows the Crown Landing project to be constructed, it would require the addition of significantly greater new pipeline infrastructure, both directly related to the Crown Landing project (i.e., additional lateral pipelines, lateral pipelines of greater diameter, or some other means to accommodate additional volumes of natural gas) and within the interconnected pipeline systems, to fully meet the increased natural gas demands predicted in the Mid-Atlantic Region. As described in more detail in the CEA report included in Attachment A, the fact that the forecasted demand in the Mid-Atlantic Region is large enough to require the construction of both the Project and the Crown Landing facility, as well as the fully subscribed volumes anticipated at the expanded Cove Point facility, the physical structures and equipment within the Crown Landing facility would effectively have to be doubled to account for the volumes anticipated to be brought into the region by the Project.

Golden Pass LNG Terminal Project – (Docket No. CP04-386-000 and CP04-400-000) Exxon Mobil Corporation – Sabine Pass, Texas – 1.0 bscfd (Phase 1), 2.0 bscfd (Phase 2) – Commission approval July 2005, under construction. In addition, the Golden Pass Pipeline project, which is approximately 77 miles in length, would have the capacity to deliver up to 2.5 bscfd of natural gas. The pipeline would cross four counties in Texas and one parish in Louisiana. At this time, up to 11 interconnections with existing intrastate and interstate pipelines are possible.

Sabine Pass LNG Terminal – (Docket No. CP04-47-000) Chewier Sabine Pass Pipeline Company – Sabine Pass Channel, Louisiana – 2.6 bscfd – Three 160,000 m^3 tanks – Commission approval December 2004, under construction. Construction began in March 2005. Terminal operations are expected to commence in 2008. The natural gas from the Sabine Pass LNG terminal will pass through the Chewier Sabine Pass LNG pipeline into the natural gas transmission network. The Chewier Sabine Pass Pipeline will run 16 miles from the Sabine Pass LNG terminal to Johnson Bayou. The proposed pipeline will interconnect with several interstate and intrastate pipelines. The pipeline is designed to transport 2.6 bscfd of natural gas.

Freeport – (Docket No. CP03-75-000) Freeport LNG Development, L.P. – Freeport, Texas – 1.5 bscfd (Phase 1), 2.5 bscfd (Phase 2) – Two 160,000 m^3 tanks (phase 1), One 160,000 m^3 tank (phase 2) – Commission approved June 2004, Phase 1 under construction. The first phase of the terminal will have a send-out capacity of 1.5 bscfd beginning in early 2008. The construction of the terminal's Phase I started on January 17, 2005, and is scheduled to be completed within 35 months. A consortium made up of Techno U.S.A Corp., Swipe Technigaz SA and Zachry Construction Corp. is providing for the construction services under a lump-sum turn-key engineering, procurement and construction (EPC) contract. Phase II will incorporate a second marine berthing dock and associated unloading facilities, expanded vaporization, 7.5 billion cubic feet (Bcf) of underground storage and a third LNG storage tank. The current schedule envisages that the construction of Phase II will start in 2006 and that the expansion will be on stream in 2008 with the exception of the third tank, which will be completed in 2009. Engineering and planning for the Phase II expansion are underway, including building a 7.5 Bcf integrated underground salt cavern storage facility.

Cameron – (Docket No. CP02-374-000) Sempra Energy, LNG – Hackberry, Louisiana – 1.5 bscfd – Three 160,000 m^3 tanks – Commission approval September 2003, construction pending. The Engineering, Construction and Procurement (EPC) contract was signed in December 2004 with the joint venture Aker Kvaerner / IHI. A Notice To Proceed with construction was granted in August 2005. In addition to the terminal, Sempra Pipelines & Storage will also be constructing a 35-mile pipeline to transport natural gas from the facility to connect with existing interstate pipelines to the north.

Weaver's Cove LNG Project – (Docket No. CP04-36-000 and CP04-41-000) Weaver's Cove Energy, LLC (Hess LNG) – Fall River, Massachusetts - 0.8 bscfd – One 200,000 m^3 tank – Commission approval July 2005 – other required permits still in process. Massachusetts recently issued its certificate finding the project in compliance with the state's environmental policy act. The USCG has agreed to an additional public meeting on navigation issues associated with the movement of ships through multiple bridges. In addition to the terminal, Mill River Pipeline will also be constructing two 6-mile pipelines to transport natural gas from the facility to connect with existing interstate pipelines to the north.

Ingleside Energy Center LNG Project – (Docket No. CP05-13-000) Occidental Energy Ventures Corp. – Ingleside, Texas – 1.0 bscfd – Two 160,000 m^3 tanks – Commission approval July 2005. The Ingleside Energy Center LNG Project is an innovative new LNG terminal and related facilities to be located in San Patricio County, Texas. The terminal is designed to provide an option for extracting natural gas liquids in addition to importing, storing and vaporizing one Bcf of gas per day. In addition to the terminal, Occidental Energy Ventures Corp proposes to construct and operate 26.4 miles of 26-inch diameter pipeline extending from the tailgate of Ingleside's LNG terminal to potential interconnections with nine interstate and intrastate pipelines located in San Patricio County.

Vista del Sol LNG Terminal Project – (Docket Nos. CP04-395-000, CP04-405-000, CP04-374-000) ExxonMobil Corporation – Corpus Christi, Texas – 1.0 bcsfd – Three 155,000 cum tanks – FERC approval June 2005, construction pending. Exxon Mobil announced on September 25, 2006 that it has dropped plans for this project and was exploring a sale with an unidentified party.

Cheniere Corpus Christi LNG Terminal Project – (Docket Nos. CP-37-000, CP04-44-000, CP04-45-000, CP04-46-000) Corpus Christi LNG, LP – Corpus Christi, Texas – 2.6 bscfd – Three 160,000 m^3 tanks – Commission approval April 2005, construction pending . Cheniere is currently developing engineering and design specifications and has awarded the FEED and the pre-EPC to AMEC/Zachry to perform work for the facility. Cheniere began site preparation in the second quarter of 2006, and expects to commence terminal operations in early 2010. The natural gas from the Corpus Christi LNG terminal will pass through the Cheniere Corpus Christi LNG pipeline into the existing natural gas transmission network. The Cheniere Corpus Christi Pipeline will run 24 miles from the terminal to a connecting pipeline north of Sinton. The proposed pipeline will interconnect with several interstate and intrastate pipelines. The pipeline is designed to transport 2.6 Bcf per day of natural gas.

Excelerate Energy, L.L.C. – Excelerate currently owns and operates the only offshore LNG terminal in the United States. The terminal, which is based on a transport and regasification vessel, is located in the Gulf of Mexico offshore of Louisiana. The terminal requires use of a specialized LNG ship, which is able to dock at a mooring system made up of a submerged turret buoy and flexible riser connected to a natural gas pipeline on the seafloor. After docking is complete, LNG is vaporized onboard the LNG ship and injected as natural gas directly into the offshore pipeline for delivery to onshore markets. When not in use, the buoy and flexible riser system would be lowered below the surface and held in position until retrieved by the next LNG ship. This design does not provide for LNG storage so it must be limited to an LNG fleet with regasification equipment on all of the vessels. Currently, there are only two such ships in the world, but a third ship is scheduled to be completed in the fall of 2006, and two more ships have been ordered and are scheduled to be delivered in 2008 and 2009, respectively. Due to the travel times to and from LNG producing countries, more specialized ships would be necessary to ensure continuous delivery of natural gas.

10.3.1.2 LNG Terminal Expansions

The Commission also authorized expansions at four previously authorized LNG facilities. In each case the Commission will require the applicant to deliver the LNG in a format that is compatible with the existing natural gas infrastructure. Descriptions for each of these projects were derived from the Final EIS for the Crown Landing Project (Crown FERC, 2006).

Elba Island - Southern LNG, Inc. (Southern LNG) – (Docket No. CP05-388-000) owns and operates an LNG import terminal located at Elba Island along the Savannah River in Chatham County, Georgia. Southern Natural Gas filed an application for an expansion, , for authorization to construct and operate a total of 176.43 miles of 24-inch and 30-inch diameter pipeline, three new compressor stations (totaling approximately 31,050 hp), and other appurtenant facilities. The pipeline project, known as the Cypress Pipeline Project (located in Georgia and Florida), would be constructed in three phases with phased in-service dates of May 1, 2007; May 1, 2009; and May 1, 2010. If constructed, the project would be able to provide 500,000 decatherms per day of firm transportation capacity to its potential customers, which are BG LNG, Florida Power Corporation doing business as Progress Energy Florida, Inc., and the City of Austell, Georgia. The Cypress Pipeline Project, which would serve customers in the southeast states of Florida and Georgia, would receive its gas from the Elba Island LNG supply. On December 21, 2005, Southern LNG (through El Paso Corporation) announced proposals to further expand the Southern LNG terminal. The proposed expansion, referred to in the announcement as the Elba Island Expansion and Related Pipeline Project, would more than double the LNG storage capacity at the terminal and would add 0.9 bscfd of send-out capacity, increasing the total send-out capacity of the terminal to 2.1 bscfd. In addition, the unloading docks at the terminal would be modified to accommodate new, larger LNG ships. A new 191-mile interstate natural gas pipeline with a total capacity of 1.1 bscfd would also be constructed from Elba Island to markets in Georgia and through interconnections with other pipelines to the Southeastern and Eastern United States. This pipeline would consist of about 105 miles of 42-inch diameter pipeline and 86 miles of 36-inch diameter pipeline. According to the project announcement, Shell NA LNG, LLC, a subsidiary of Royal Dutch Shell, and BG LNG, a wholly owned subsidiary of BG Group PLC, have entered into long-term agreements for the incremental storage and sendout capacity of the announced expansion and for the transportation capacity on the new Elba Express pipeline.

CMS Trunkline LNG Company, L.L.C. (Trunkline LNG) - (Docket Nos. CP02-60-000 and CP02-60-001) currently owns and operates an LNG import facility in Calcasieu Parish, Louisiana. The existing LNG terminal includes three 95,000 m^3 storage tanks, a ship unloading dock with a full design capacity of 120 ships per year, and vaporization facilities with a maximum sendout capacity of 1.0 bscfd. In December 2002, the Commission approved plans to add a second ship unloading dock, a 140,000 m^3 LNG storage tank, three first stage LNG pumps, four second stage LNG pumps, three vaporizers, and two electric generators. With the addition of these facilities, which are currently under construction, the LNG terminal will have a sustainable sendout capacity of about 1.2 bscfd (1.3 bscfd maximum) and a ship unloading capacity of about 175 ships per year. In February 2004, Trunkline LNG and a related subsidiary, CMS Trunkline Gas Company, L.L.C. (Trunkline Gas), announced plans to further expand sendout capacity of the terminal by adding pumps, vaporizers, and new unloading facilities to a second dock at the terminal and constructing a new 23-mile-long, 30-inch diameter pipeline between the LNG terminal and Trunkline Gas's existing mainline pipeline system. If approved, these new facilities would increase the maximum sendout capacity of the terminal to about 1.8 to 2.1 bscfd. Trunkline LNG currently has signed agreements with BG LNG Services, L.L.C. (BG LNG) for all of the storage and sendout capacity that will be provided by the expanded facilities. After these expansions are completed, the Trunkline LNG facility is unlikely to have space for more storage tanks within its 125-acre fenced site. Further expansion outside of the existing fenceline is limited by other industrial facilities. Another factor potential limiting additional expansion of the Trunkline LNG facility is its ability to deliver increased volumes of natural gas to an interstate natural gas pipeline system. If the proposed pipeline is constructed, the Trunkline LNG facility would be connected to a mainline pipeline by two (one existing and one proposed) 30-inch diameter pipelines.

Sabine Pass LNG – (Docket No. CP05-396) The Commission approved an expansion of the proposed Sabine LNG project, which was authorized in December 2004 to be constructed and operated in Cameron Parish, Louisiana. In its decision, the Commission also approved Phase II of the project, which includes three additional 160,000 m^3 storage tanks and related facilities that would provide an average send-out capacity ranging from 2.6 bscfd to 4 bscfd. The Sabine LNG Phase II facilities are proposed to be adjacent to or within the boundary of the Phase I site.

Dominion Cove Point LNG – (Docket Nos. CP05-130-000, CP05-130-001, CP05-130-002; CP05-132-000, -001) Dominion Cove Point owns and operates an LNG import facility near

Lusby, Calvert County, Maryland and a pipeline, known as the Cove Point pipeline (Docket No. CP05-131), that extends approximately 88 miles from the LNG terminal to connections with several interstate pipelines in Loudoun and Fairfax Counties, Virginia. Currently, the LNG terminal has a storage capacity of 7.8 Bcf and a peak send-out capacity of 1.0 bscfd.

Conclusions Regarding Approved LNG Terminal Alternatives

Given the forecasted decrease in production of natural gas in certain supply basins, LNG is projected to supply not only incremental natural gas demand, but it also could replace the projected reduction in other supply components (i.e., natural gas imports from Canada and certain United States production basins). Alternatives outside of the defined market area are not considered commercially feasible for serving the Mid-Atlantic Region due to tariff transportation charges and/or pipeline constraints. Delivery of natural gas from LNG terminals outside of the defined market would require construction of additional delivery capacity over significantly greater distances than required for in-area projects; thus, leading to greater human and environmental impacts. Finally, LNG projects located outside of the Mid-Atlantic Region would not have the same Project benefit of introducing new natural gas storage capacity into the area.

By the 2020 time period, AES has forecasted that incremental design day demand and supply-in fill of approximately 4.921 bscfd will not only require the 1.5 bscfd from the Sparrows Point Project but will also require approximately two additional natural gas supply projects that are larger than the size of the Sparrows Point Project. In other words, by 2020 the Mid-Atlantic Region would have sufficient demand of approximately 4.921 bscfd which would not only absorb the Sparrows Point volume of 1.5 bscfd, but also the Crown Landing volume of 1.2 bscfd, the Cove Point expansion of 0.8 bscfd, and still require approximately 1.4 bscfd of other supply.

For these reasons, neither the expansion of the existing LNG terminals nor the proposed construction of the approved LNG terminal projects listed above, would be a viable system alternative to the Project. The majority of the projects listed above propose to serve natural gas markets substantially farther north or south of those intended to be served by the Project. A LNG facility that is not located within the defined market analyzed by AES could not serve the Mid-Atlantic Region without substantial expansions of existing pipeline systems.

10.3.1.3 Proposed LNG Terminals

Several other proposals for LNG Terminals are before the Commission or USCG, including the following:

Northeast Gateway – (USCG Docket No. 22219) Excelerate Energy LLC is proposing to construct the Northeast Gateway deepwater port offshore from Gloucester, Massachusetts. The terminal would have a send-out capability of an average of 0.8 bscfd. No storage tanks are proposed. The USCG deemed the Northeast Gateway application complete on September 2005. The NEPA review timeline has been suspended as of November 2005.

Neptune – (USCG Docket No. 22611) Tractebel (Suez Energy) is proposing to construct the Neptune deepwater port offshore from Gloucester, Massachusetts. The terminal would have a send-out capability of an average of 0.8 bscfd. No storage tanks are proposed. The USCG deemed the Neptune application complete on October 2005. The NEPA review is ongoing.

Main Pass Energy Hub Deepwater Port Project – (USCG Docket No. 17696) Freeport-McMoRan Energy LLC is proposing to construct the Main Pass Energy Hub Deepwater Port in the Gulf of Mexico offshore of Louisiana. The terminal would have a send-out capability of an average of 1.0 bscfd. Natural gas storage facilities have not been proposed. The NEPA review process was suspended in August 2005.

Compass Port Terminal Project – (USCG Docket No. 17659) ConocoPhillips is proposing to construct the Compass Port Terminal Project approximately 11 miles off the coast of Alabama near Daupin Island. The terminal would have a send-out capability of an average of 1.0 bscfd with storage facilities for 250,000 m^3 of natural gas. The NEPA review timeline has been suspended as of August 2005.

Beacon Port Deepwater Port Project – (USCG Docket No. 21232) ConocoPhillips is proposing to construct the Beacon Port Deepwater Port Project off the coast of Louisiana in the Gulf of Mexico. The terminal would have a send-out capability of an average of 1.0 bscfd with two natural gas storage tanks. The NEPA review timeline has been suspended.

Broadwater LNG Facility – (FERC Docket No. PF-05-4-000) TransCanada Corporation and Shell US Gas & Power LLC are proposing to construct the Broadwater LNG Facility within the Long Island Sound in New York. The terminal would have a send-out capability of an average of 1.0 bscfd with a floating regasification unit with 350,000 m^3 of natural gas storage capacity. Broadwater LNG facility was filed with the Commission in January 2006. Additional discussion of the Broadwater LNG Facility is provided in Section 10.5.1.1.

Casotte Landing LNG – (FERC Docket No. CP05-420-000) Bayou Casotte Energy LNG – Bayou Casotte, Mississippi – 1.3 bcsfd – tbscfd – hree 160,000 m^3 tanks – Application filed October 2005, environmental review underway. The proposed Casotte Landing project, to be located adjacent to Chevron's Pascagoula Refinery, will process imported LNG for distribution to industrial, commercial and residential customers in Mississippi and the U.S. Southeast region, including the growing Florida market. The terminal would have an initial processing capacity of 1.3 bscfd.

LNG Clear Energy – (FERC Docket No. CP06-12-000, CP06-13-000) Gulf LNG Energy, LLC – Pascagoula, Mississippi – 1.5 bscfd – Two 160,000 m^3 tanks – Application filed October 2005. The Project will be sited on land controlled by the Jackson County Port Authority and Jackson County. The site is adjacent to the Bayou Casotte ship channel (east harbor).

LNG Clear Energy – (FERC Docket No. CP06-12-000, CP06-13-000) Gulf LNG Energy, LLC – Pascagoula, Mississippi – 1.5 bcsfd – Application filed October 2005. The Project will be sited on land controlled by the Jackson County Port Authority and Jackson County. The site is adjacent to the Bayou Casotte ship channel (east harbor).

Quoddy Bay LNG – (FERC Docket No. PF06-11-000) Quoddy Bay, LLC – Pleasant Point, Maine - 0.5 bcsfd – three 160,000 m^3 tanks – NEPA Pre-filing process initiated December 2005. The LNG import terminal will be located at the Pleasant Point Reservation of the Passamaquoddy Tribe. The storage facility will be located in the Town of Perry. The Project includes a 35.8-mile natural gas sendout pipeline to transport natural gas from the LNG Terminal to the interstate natural gas pipeline in the Town of Princeton. The sendout pipeline originates at the import facility in Western Passage of Passamaquoddy Bay, and extends northwest through the reservation and the Towns of Perry, Pembroke, Charlotte, Cooper, Alexander, and Princeton before reaching the interstate natural gas pipeline interconnect.

Conclusions Regarding Proposed LNG Terminal Alternatives

Given the forecasted decrease in production of natural gas in certain supply basins, LNG is projected to supply not only incremental increases in natural gas demand, but it also could replace the projected reduction in other supply components (i.e., natural gas imports from Canada and certain United States production basins). Alternatives outside of the defined market area are not considered commercially feasible for serving the Mid-Atlantic Region. Delivery of natural gas from LNG terminals and other sources outside of the defined market would require construction of additional delivery capacity, over significantly greater distances than required for in-area projects, with resultant additional environmental and landowner impacts and effectively limits them from serving the Mid Atlantic Market[10].

In addition, with respect to terminals proposed in the Northeast, it is highly unlikely that any natural gas delivered to those terminals could be delivered to the Mid-Atlantic Region, even assuming the additional pipeline infrastructure required was constructed, due to the tremendous demands in the greater New York City region and other nearby areas. Those demands would effectively siphon off all incremental supplies before they could reach the Mid-Atlantic Region. Similarly, LNG introduced into Maine or Massachusetts will be used to meet growing demand in New England, and would not be available to the Mid-Atlantic region.

Moreover, proposed projects without storage capability (Excelerate, Neptune) would only be able to provide interruptible service as compared to the firm service that would be available from the Sparrows Point Project.[10] Projects that make use of specialized ships are similarly prone to interruptions. These considerations make such alternatives even less viable than other fixed base facilities when determining their potential use in lieu of the Project proposed by AES.

10.4.2 Pipeline System Alternatives

An alternative to constructing the proposed Project is utilizing or expanding exiting pipeline systems to provide an equivalent 1.5 bscfd of natural gas to the Mid-Atlantic Region. The first drawback to such an alternative is the fact that onshore conventional natural gas production is anticipated to decline from 4.8 Tcf in 2004 to 4.2 Tcf in 2030, while net pipeline imports are expected to decline from 2004 levels of 2.8 Tcf to about 1.2 Tcf by 2030 due to resource depletion and growing domestic demand in Canada. The decline in overall supply from the west coast of the Unites States and Canada is coupled with an increase in consumption from 22.4 Tcf of natural gas in 2004 to 26.9 Tcf in 2030 (EIA 2006). Not only does reliance on this alternative not meet the Project objective of introducing a new source of natural gas into the Mid-Atlantic Region, it also has a negative effect on the supply/demand equation as this alternative looks to decreasing supplies to meet increasing demands.

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[10] Offshore terminals in general are expected to provide only interruptible service due to interruptions caused by high seas or other inclement weather that affect the ships ability to stay moored and off-load at open ocean moorings.

The second, more obvious, drawback to this alternative is the fact that it does not meet the stated Project objective of increasing access to world natural gas production centers in the Mid-Atlantic Region. The United States is expected to depend increasingly on imports of LNG to replace Canadian pipeline imports and tap the world supply of natural gas. Approximately 74 percent of the world natural gas reserves are located in the Middle East and Eurasia, compared with less than four percent within North America (EIA 2006). To meet a projected demand increase of 4.5 Tcf from 2004 to 2030 and to offset an estimated 1.6 Tcf reduction in pipeline imports, the United States is expected to rely on the world supply of natural gas through LNG.

Finally, the alternative of utilizing or expanding existing pipeline systems to provide an equivalent 1.5 bscfd of natural gas to the Mid-Atlantic Region would not carry the additional benefit of introducing new facilities for natural gas storage in the Region.

10.4.2.1 Existing Pipeline Systems

Existing pipeline systems in the Mid-Atlantic Region, including those owned and operated by TETCO, Columbia, and Transco (see Figure 10.4.2-1), were also evaluated. All of these pipeline systems primarily provide natural gas from production areas in Canada and the Gulf Coast. Because the production from conventional natural gas reserves in the United States and Canada are anticipated to decline, it is unlikely that pipeline alternatives connected to these reserves would be able to meet the project objective of providing up to a maximum rate of an additional 1.5 bscfd of natural gas to the Mid-Atlantic Region (EIA, 2006).

Furthermore, based on information from AES's recent discussions with Columbia, Transco, and TETCO, the existing pipeline systems do not have sufficient forward haul capacity to deliver the incremental volumes proposed by AES without expansion. Based on a Commission evaluation of the Columbia and Transco pipeline systems conducted during the preparation of the Dominion Cove Point Expansion EIS (Dominion EIS), the systems are fully subscribed and there is no capacity to transport additional gas supplies without substantial expansion or modifications similar or greater than those proposed by the Project. Deliveries by AES to the interstate pipelines in the Eagle, Pennsylvania area will allow delivery of natural gas closer to the market consuming areas. Volume from these interconnections will be able to be delivered on a firm back haul basis to markets south and west of these interconnects, and, at least initially, on an interruptible basis to markets north and east of these interconnects. In addition, existing firm shippers would have the ability to segment their existing long haul capacity by accepting additional supply from the Project, which greatly increases transportation options available. As the market requires more incremental firm forward haul delivery capacity expansions from the point of the proposed Pipeline and forward, those interconnects should be less costly and carry less environmental impact.

It is anticipated that proposals to expand existing pipelines will continue to increase the capacity of existing natural gas pipeline systems to the Mid-Atlantic Region. However, these projects cannot meet the Project objective of providing access to new natural gas supplies from around the world in the Mid-Atlantic Region. Further, significant pipeline expansion projects, such as would be required to deliver the same gas volumes to the Mid-Atlantic Region as proposed by AES, typically result in short and long term impacts on water resources, upland vegetation, wetlands, wildlife habitats, traffic patterns, and land use, as well as impacts to landowners. In addition to construction-related effects, the operation of such longhaul pipelines require compressor stations that would result in permanent noise and air quality impacts. Because this alternative does not meet the Project objective of providing access to new natural gas supplies from around the world, and there are an almost infinite variety of expansion alternatives, no attempt was made to quantify these impacts.

10.4.2.2 Proposed Pipeline Systems

Current proposals to deliver natural gas reserves from the west coast of the Unites States and Canada to the eastern market were evaluated by AES in its consideration of potential alternatives to the Project. No similar project proposals in the Gulf Coast region of the United States were identified.

Rockies Express Pipeline, which is being developed by Rockies Express Pipeline LLC, is a joint development between Kinder Morgan Energy Partners and Sempra Pipeline & Storage (Rockies Express Pipeline 2006). The project consists of a proposed 1,663-mile natural gas pipeline system from Rio Blanco County, Colorado, to Monroe County, Ohio.

The Mackenzie Gas Project proposes to build an approximate 760-mile 30-inch diameter pipeline system along the Mackenzie Valley (Mackenzie 2004). The project will connect three discovered natural gas fields in the Mackenzie Delta - Taglu, Parsons Lake and Niglintgak to distribution systems in Alberta Canada for transmission to markets in Canada and the United States. The pipeline is also anticipated to be utilized by other companies exploring for natural gas in northern Canada to supply as much as 1.2 bscfd of natural gas through the Mackenzie Valley Pipeline.

While construction of new pipelines would increase the amount of natural gas to the Mid-Atlantic Region, and such new pipelines might originate at production centers not currently used to supply the Mid-Atlantic Region, such alternatives cannot meet the Project objective of increasing access to new natural gas supplies from around the world in the Mid-Atlantic Region. Further, significant new pipeline construction projects, such as would be required to deliver the same gas volumes to the Mid-Atlantic Region as proposed by AES, typically result in short and long term impacts on water resources, upland vegetation, wetlands, wildlife habitats, traffic patterns, and land use, as well as impacts to landowners. In addition to construction-related effects, the operation of such longhaul pipelines require compressor stations that would result in permanent noise and air quality impacts. Because this alternative does not meet the Project objectives described above, no attempt was made to quantify these impacts.

10.5 Aboveground Alternatives

AES conducted an alternatives analysis of all major aboveground facilities, specifically the location for the LNG Terminal. Other major aboveground facilities associated with this Project are not anticipated, including compressor stations along the Pipeline Route. AES also evaluated design alternatives options for the LNG Terminal, including pier design, regasification methods, and dredge method and dredge disposal alternatives.

10.5.1 LNG Terminal Site Alternatives

Following the system alternatives analysis, AES evaluated several factors to determine the extent to which alternative LNG terminal site locations would fulfill the purpose for the Project (i.e. introducing a new incremental supply of natural gas from world production centers into the Mid-Atlantic Region, which includes the Baltimore area market to meet the growing demand for energy in those markets in a safe, reliable and economic manner). To meet this purpose, AES determined that, at a minimum, an LNG terminal site would need to satisfy the criteria below. The noted criteria are listed in no particular order of importance; rather, all of the criteria are considered important to the determination of site alternatives.

- Geographic Location. Given the impracticality of LNG Terminal System Alternatives to serve the intended markets (see discussion in Section 10.4.1), it is necessary to locate the Project within the Mid-Atlantic Region to allow adequate interconnection with existing natural gas pipeline systems in the vicinity of the Terminal Site. Furthermore, due to the projected increase in demand for natural gas throughout the country, the location of the project is crucial to insure that the increase in capacity (or the great majority thereof) is used to satisfy the increased demand within the Mid-Atlantic Region.[11] Because the project adds storage capacity in the region, it will ensure immediate availability without regard to pipeline capacity constraints in times of peak demands. The specific definition of the intended market area for this Project, and the basis for the need for the Project are described in Resource Report 1, *General Project Description*¸ in Sections 1.1 and 1.2.

- Distance from Residential Concentrations. AES considered only locations of the Terminal Site and associated LNG transit vessel routes that were – at all times – greater than one mile from residential communities and population centers. Although the Commission has recently approved projects with ship transit routes closer to residential areas (Crown Landing – approximately 0.6 miles from Wilmington and similar distances from other cities or towns in both Delaware and New Jersey; Weaver's Cove – approximately 0.5 miles from Fall River), and while not required by any applicable regulations or recent practice, AES has made the corporate decision to follow this one-mile guideline. The guideline is based on recent studies conducted by Sandia National Laboratory (SNL) that sets out a worst-case marine-related thermal event as causing potential harm to persons within approximately one-mile (5,280 feet or 1,600 meters) of an LNG spill. Studies cited by SNL corroborate this distance.[12] This distance is also corroborated in comments submitted by the LNG Opposition Team wherein

[11] It was noted in Section 10.4.1 that small amounts of natural gas imported through the LNG terminals at Lake Charles and Elba Island might find their way into the Mid-Atlantic Region, and that expansions of those terminals were recently approved by FERC. Regardless of the size of the approved expansions, existing pipeline capacities from those areas do not allow for the introduction of the same quantities of natural gas as proposed to be delivered through the Project without significant expansions of existing pipeline systems from those areas or construction of new pipeline systems. Pipeline systems alternatives are discussed in Section 10.4.2.

[12] *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*, Sandia National Laboratories SAND2004-6258 (December 2004), cited to four recent LNG spill-modeling studies that included reports by Lehr and Simicek-Beatty, Fay, Quest, and Koopman. The calculated "skin burn" distances (the point at which a heat flux value of 5kW/m^2 could be conservatively measured) in each of these reports was listed as 500 meters (Lehr), 1,900 meters (Fay), 490 Meters (Quest), and 1,290 meters (Koopman). In a subsequent study, Fay indicated that the "skin burn" distance was 1,100 meters (*Spills and Fires from LNG and Oil Tankers in Boston Harbor*, March 26, 2003).

the group makes citation to Massachusetts legislation that would require a terminal set-back distance from residential areas of 5,000 feet and a ship transit set-back distance of 1,500 feet.

- Land Use Compatibility. Development of LNG projects has emerged as one of the most contentious energy infrastructure issues in recent years. There are several reasonable explanations for the attention such projects have drawn, including (i) the regulatory process has encouraged, and sometimes required, public participation often prior to the time the applicant has completed site-specific studies; (ii) the projects are generally of significant size (a project cost of $500 million is not unusual) so that they are difficult to ignore or overlook, and (iii) a great deal of misinformation exists about LNG; and (iv) because of the relatively small number of major LNG import terminals in the United States, large scale LNG projects are perceived as unsafe. In such a situation, it is incumbent upon the applicant to identify areas for potential location that are compatible with existing land use regulations and published community development plans. As described more fully in Resource Report 5, *Socioeconomics*, and Resource Report 8, *Land Use, Recreation and Aesthetics*, the Project complies with the existing industrial zoning at the Terminal Site, and does not conflict with the Dundalk Renaissance Plan titled *Dundalk, A Second Century Vision*, and the Turner Station Community Conservation Plan.

- Technical and Economic Feasibility. AES investigated the technical and economic feasibility of constructing and operating an LNG terminal at the proposed site. Factors considered in this investigation include: site access to nearby deepwater port facilities (requiring a nominal 45-foot draft); access to adequate constructible land (requiring a nominal 40 acres); availability of adequate air draft under bridge crossings and distance of bridge locations from the proposed site; proximity to (or, preferably, location within) natural gas markets intended to be served by the Project[13]; ability of the site to accommodate LNG terminal facilities (*i.e.*, vessel berthing and off-loading facilities, LNG storage tanks, regasification plant, administration buildings and other associated facilities); and ability to avoid or minimize disruption of channel traffic while LNG vessels are in transit or at berth.

- Safety and Security. The selected site must be able to satisfy all applicable safety and security standards. As pointed out in the second criterion above, Distances from Residential Concentrations, it may be appropriate to consider going beyond the minimum safety and security standards established by the applicable regulations.

- Site Acquisition. The ability of AES to gain site control in a reasonable and timely manner was an important criterion in selecting the Terminal Site as an appropriate location for the LNG Terminal. To meet the Commission's requirement that the applicant demonstrate site control before filing an application, the site must be available to AES (i.e. at open market commercial terms, without the need for extraordinary acquisition methods or condemnation required for site control). This is the basis for this siting criterion.

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[13] See discussion in Section 10.4 regarding system alternatives. In summary, alternatives outside of the defined market area are not considered commercially feasible for serving the same market as the Sparrows Point Project due to the need to construct additional delivery capacity over significantly greater distances than required for in-area projects. Resource Report 1, *General Project Description* (summary of the market to be served); and footnote 10, Section 10.4.2.

- Environmental Impact. A very important siting criterion employed by AES is the ability to avoid or minimize potential impacts to the natural environment, cultural resources and stakeholders associated with the proposed Project. The information contained in Resource Reports 2 through 13 provides ample evidence that this criterion has been satisfied with the selection of the Terminal Site for location of the LNG Terminal portion of the Project.

  Consideration of the criteria noted above led to numerous site alternatives located both on and offshore within the Mid-Atlantic Region. Alternatives outside of the general geographic region were not considered feasible for the reasons described in Section 10.4.1, which described LNG terminal alternatives in the Gulf of Mexico and northeast areas of the United States. A discussion of the more important design features considered by AES is provided below. Based on these important design features, a review of alternative offshore and onshore site locations is performed.

10.5.1.1 Design Factors – Technical and Economic Feasibility

Deepwater Access

Of the design factors, the most important design factor considered by AES was site access to nearby deepwater port facilities. Without such access, the LNG ships required to bring the new source of natural gas to the Mid-Atlantic Region from world production centers could not unload their cargos. This would serve to frustrate the stated objectives of the Project. Dredging of any significant magnitude also presents the potential to seriously disturb or impair the human and natural environments in the vicinity of the dredging activities.[14] While other design factors (e.g., adequate constructible land, adequate air draft under bridges and distance from bridges, proximity to natural gas markets intended to be served by the Project, and ability of the site to accommodate LNG terminal facilities) also have the potential to disturb or impair the human and natural environments, the impacts are considerably less than the impacts associated with significant dredging and are considered manageable. Accordingly, AES conducted a detailed review of vessel drafts and waterway depths.

Within the Mid-Atlantic Region, there are only two waterways with sufficient depth to potentially accommodate LNG vessel traffic for an onshore terminal: the Chesapeake Bay region and the Delaware River region. The Chesapeake Bay region has shipping channel depths of 50 feet or more. The Delaware River region has shipping channel depths limited to 40 feet. In order to determine whether the limited depth of the Delaware River might impact the stated Project objectives, AES reviewed the range of LNG transport vessels anticipated for use in connection with the Project. Such vessels included both the existing world fleet of LNG ships and a limited number of larger vessels currently in design and/or under construction.

There are currently approximately 207 LNG carriers in service worldwide. These range in cargo carrying capacity from 1,100 m^3 to 149,172 m^3. A review of the current shipbuilding backlog

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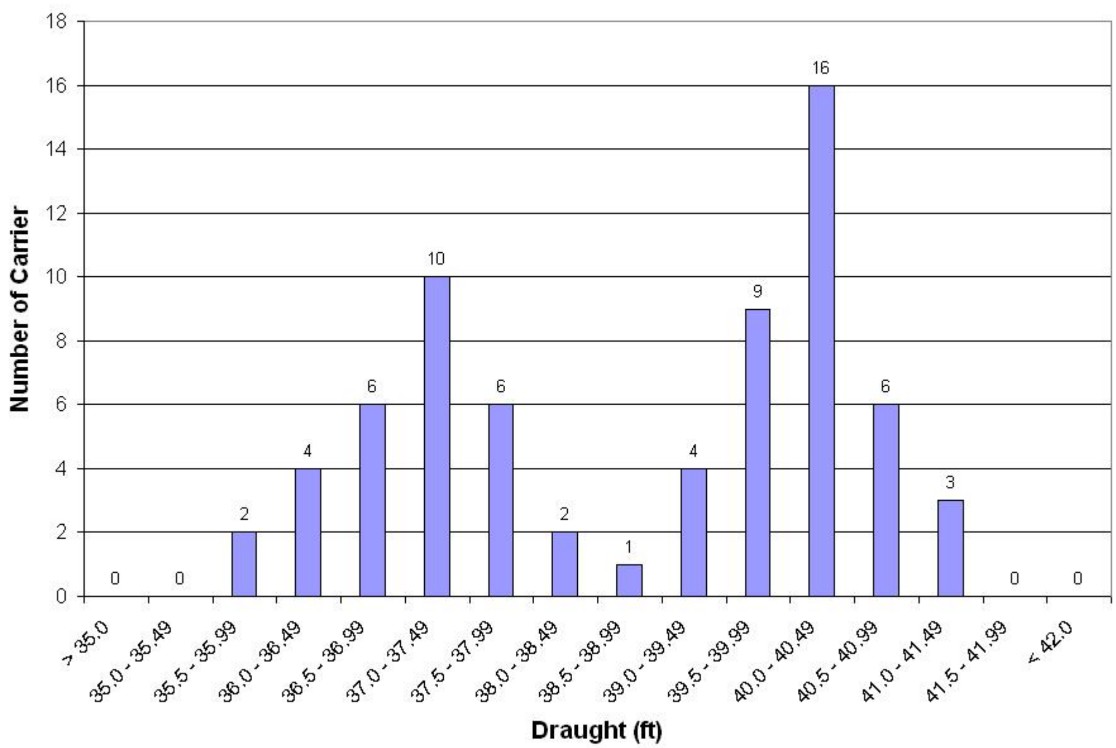
[14] It is recognized that dredging may also result in certain benefits to a particular waterbody. These situations occur where contaminated sediments may be safely and permanently removed and disposed of properly. See for example papers presented at ***"Environmental Forensics: Urban Ports & Harbors - Sediment Assessments in Complex Systems",*** conducted Baltimore, MD 26-27 September 2006.

indicates that there are currently 145 LNG ships on order (firm and options); out of which only four have a capacity less than 125,000 m^3. All four of those smaller ships are to be dedicated for Coastal and inter-Mediterranean trades. The remaining vessels on order have a capacity greater than 138,000 m^3. In light of this above trend, AES has designed the LNG Terminal to accommodate LNG carriers with a capacity ranging from 125,000 m^3 to 217,000 m^3. As outlined in Resource Report No. 1, the anticipated draft of vessels expected to call the proposed AES LNG Terminal is anticipated to range from 37.7 to 40.5 feet.[15] AES believes that the use of smaller LNG carriers is not practical, as the current and aging fleet of small LNG carriers with a capacity less than 125,000 m^3 is heavily dedicated[16] and the vast majority of the proposed LNG carriers on order have a cargo carrying capacity greater than 138,000 m^3.

Figure 10.5.1-1 shows the distribution of the drafts for all of the vessels currently operating in the Atlantic Basin (except the seven vessels for which draft information was not available). It is important to note that the distribution shown below is also representative of the entire fleet of the currently operating LNG carriers in the above-referenced capacity range.



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[15] Current plans exist for LNG ship designs up to 250,000 m^3 in cargo carrying capacity. AES eliminated ships larger than 217,000 m^3 in capacity for reasons similar to the rationale for not limiting the project to use of ships with capacities less than 138,000 m^3 – the distribution suggests that the widest possible use of the LNG Terminal will be made up of ships between the 125,000 m^3 and 217,000 m^3 classes.

[16] Energy Information Administration (EIA – 2001 to 2006) indicates that spot market shipment availability is only recently becoming available, primarily due to new ship construction, indicating subscription for existing fleet vessels (including smaller capacity ships) is full to nearly full.

Figure 10.5.1-1 – Distribution of the Draft of LNG Carriers in the Atlantic Basin with a Cargo Carrying Capacity Greater than 125,000 m^3

While it might appear that a vessel draft of 40.5 feet (12.3 meters), which is the deepest draft vessel proposed to call at the LNG Terminal, would fit within a 40 foot channel, this is not the case. The required navigational channel depth is a function of the static draft of the largest vessel expected to transit the waterway, squat, trim, vertical ship motion due to wave action, fresh water adjustment, under keel clearance, and tolerance for dredging and sounding accuracy. For security, economical, and practical reasons, LNG carriers must be able to navigate at all tide conditions. As such, no tidal allowance must be considered in defining the required minimum channel depth (i.e. it cannot be assumed that a vessel will transit a waterway only at high tide). Table 10.5.1-1 shows the required minimum channel depth based on vessel transit speed.

Table 10.5.1-1: Minimum Channel Depth Parameters for Safe Transit of LNG Vessels.

Parameters	Transit Speed (knots)		
	0 to 3.0 (1)	6 (2)	10 (3)
Static Draft	40.5	40.5	40.5
Squat	0	0.7	2.3
Trim	0	0	0
Exposure Allowance	0	0	0
Fresh water Adjustment	1	1	1
Under keel Requirement	3	3	5
Dredging Tolerance and Sounding Accuracy	0.5	0.5	0.5
Minimum Required Depth	45.0	45.7	49.3

Notes:
(1) Final approach to the terminal, turning, and docking
(2) Transit to the terminal while made fast to tugs
(3) Transit from the mouth of the Delaware to the proposed Crown Landing LNG terminal

According to the above, the minimum channel depth required for a slow transit speed is about 45.0 feet and 49.0 feet for a fast transit speed. Thus, a channel depth of 40 feet as available in the Delaware River would not be sufficient for Project purposes.[17] Note that drafts less than that required for a slow transit speed, i.e., during tug-assisted maneuvering and docking, are allowed. Given the discussion above, AES estimated that approximately 59.4 million yards of dredging would be required to obtain the required depth in the Delaware River to support the Project. This estimate is based on the current average depth of the channel of approximately 40 feet, that the required depth is 50 feet, and the distance from the Brown Shoals to the Crown Landing facility is approximately 38 miles at a width of 800 feet. The 800 foot channel width is consistent with information provided in the Final EIS for the Crown Landing Project at p. 3-34 (Crown FERC, 2006).

Disruption of Maritime Traffic

Another important design factor considered by AES was the ability of the site to avoid disruption of commercial maritime recreational and other commercial traffic while LNG vessels are in transit or at berth. AES has held meetings to discuss potential impacts associated with the proposed project with the Maryland Department of Natural Resources ("DNR") Tidal Fisheries and Sport Fish Advisory Commissions, and with three fishing associations: the Maryland Waterman's Association, the Maryland Saltwater Sport Fisherman's Association and the Upper Bay Charter Captains Association. These three associations were selected in an effort to cover the range of fishing that takes place in the Chesapeake Bay – commercial, recreational, and charter boat. The organizations expressed several common concerns, the most significant being the impact of a moving security zone that might impact their activities, alleged overly aggressive enforcement of the existing security zone at Cove Point by the USCG, and the fear that the same aggressive

[17] According to NOAA/US Department of Commerce Navigation Chart No. 12312, the dredged depth for the navigation channel in the Delaware River is 40 feet, which is significantly less than the required minimum depth.

enforcement policies would be applied in the upper portions of the Chesapeake Bay. AES is currently working in conjunction with the USGC to develop LNG vessel transit schedules and security zones that would provide the maximum amount of protection for LNG vessels, while at the same time minimizing disruption to commercial and recreational traffic. Different approaches to establishing and enforcing a moving security zone around inbound LNG tankers were explored in an effort to accommodate as many waterway users as possible without lessening security to an unacceptable degree. The potential strategies, including modified arrival schedules and modified moving security zones for LNG vessels, fall under the jurisdiction of the USCG. The ultimate strategies to be applied to the Project will be determined through the Waterway Suitability Assessment (WSA) process, which is further described in Resource Report 11, *Reliability and Safety*.

In an effort to proactively minimize disruption to communities and commercial and recreational vessel traffic, AES sought out a vessel transit route that would allow an LNG ship to maintain a minimum one mile distance from populated shore areas during transit and while at berth. Additionally, AES sought a berth site that was near a protected harbor and closer to the nearshore area. By locating the berthing area farther from the designated transit routes, impacts to deeper draft vessels including both commercial and recreational will be minimized. While, as noted above, standoff distances for vessels in transit and at berth will ultimately be determined by a quantitative review performed by the USCG during the WSA process, AES performed this initial qualitative assessment to locate a terminal site that would minimize impacts to vessel traffic to the maximum extent practicable while also providing a sufficient buffer between the terminal facilities and populated areas. The qualitative assessment of this design factor led to the same conclusion as the assessment of the need for deep water access for an onshore facility – the Chesapeake Bay is the only water body within the general vicinity of the Mid-Atlantic Region capable of accommodating the objectives of the Project.

Conclusions Regarding Design Factors

Even if it were technically, economically, and environmentally feasible to undertake the dredging required to access sites within the Delaware River region, AES determined that no site within this region would be capable of satisfying its other selection criteria, principally the ability to locate the site and conduct LNG vessel transit one-mile distant from residential communities and other population centers, and minimize impact to other vessel traffic while at berth. In addition, AES is unable to determine whether it could obtain site control for any acceptable site in this region on acceptable terms. For these reasons, AES eliminated those sites within the Delaware region from its alternatives evaluation, leaving for further consideration alternative sites within the Chesapeake Bay area.

10.5.1.2 Offshore LNG Terminal Sites

AES evaluated the feasibility of siting an LNG import terminal at a deepwater location offshore from the Atlantic Coast within the Mid-Atlantic Region. Such siting would be compatible with the range of LNG vessels intended for use in the Project.

AES estimates that construction and operation of an offshore LNG terminal within the open Atlantic Ocean of the Mid-Atlantic Region would be extremely difficult due to the wind, wave and current patterns experienced in this area. Extreme meteorological and oceanographic forces would result in a shortened construction season and anticipated, but unpredictable, setbacks due to weather. High wind, wave and strong current patterns would interfere with safely berthing and mooring LNG carriers and off loading LNG, resulting in lost productivity and deliverability. Furthermore, damage from severe storm events to the LNG terminal and associated offshore pipeline would further complicate operation and introduce potential impacts to the environment. These concerns are especially pronounced in the winter season when storms (other than hurricanes) in the Atlantic Ocean are more severe. Because natural gas demands peak in the winter months, such severe weather would negatively impact the predictable, constant flow of natural gas to the markets intended to be served.

Offshore locations within the Mid-Atlantic Region would also require construction of a lengthy offshore and onshore pipeline system to reach the Project's intended markets. Therefore, with certain limited exceptions, such a terminal location and pipeline system would not be considered a commercially viable alternative to the Project.[18]

Potentially feasible offshore exceptions within the Mid-Atlantic Region, i.e., offshore locations reasonably proximate to existing onshore or offshore natural gas pipeline systems, are those off of the south shore of Long Island and within the Long Island Sound. Locations off the south shore of Long Island are exposed to the Atlantic Ocean; thus, these locations likely would present the same wind, wave and current concerns noted for other offshore locations within the Mid-Atlantic Region. Long Island Sound, by comparison, is relatively sheltered from those meteorological conditions characteristic of the open Atlantic Ocean. However, to meet the stated objectives of the proposed Project, use of the Long Island Sound offshore alternative would require construction of a lengthy offshore and onshore pipeline system to reach the Project's intended markets.[19] Therefore, such a terminal location and pipeline system would not be considered a commercially viable alternative to the Project. Further, as described in more detail below with reference to the Broadwater Energy LNG Facility, connection to the more reasonably proximate pipeline systems near Long Island Sound still would not serve the intended objectives of the Project.

Broadwater Energy recently filed an application with the Commission to site, construct and operate an LNG import terminal in Long Island Sound (January 2006). That project proposes to serve natural gas markets in New York and Connecticut through an interconnection with the existing Iroquois Gas Transmission System. These markets are located substantially farther north of those intended to be served by the Sparrows Point Project. An LNG facility that is located in a downstream market (i.e., Long Island Sound) would be able to provide service only to certain markets that are within the defined market segment intended to be served by the Project (i.e., New York and New Jersey). It could not also serve markets that were further upstream than the defined market analyzed by AES such as North Carolina. However, to set realistic boundaries on

[18] In order to maintain the commercial viability of the Project, AES considered a pipeline length of 100 miles to be reasonable. See Resource Report 1, *Project Description*, for definition of these elements. In comparison with the various transcontinental pipelines described above in Section 10.3.2, the 100-mile send-out pipeline scenario would have substantially smaller relative impact.

[19] An offshore terminal in Long Island Sound would necessitate construction of a more lengthy natural gas pipeline that would extend from the offshore location (about 10 miles) to the onshore interconnection points (about 175 miles), thereby increasing the potential environmental impacts associated with construction and, as noted above, decreasing the economic viability of the Project.

the market demand analysis, certain reasonable assumptions were made regarding markets and supply sources in the CEA report.

AES also considered the feasibility of siting an LNG terminal at an offshore location within the Chesapeake Bay. However, if sited within an existing deep water channel, AES determined that such an alternative location could have a significant adverse impact on commercial maritime, recreational, and commercial and recreational fishing vessel traffic within the Bay due to the safety and security zones that likely would apply to the offshore terminal location.[20] Outside of the main deepwater channel located in the center of the Chesapeake Bay, the Chesapeake Bay is a shallow estuary with an average depth of approximately 21 feet (Chesapeake Bay Foundation 2006). A location within the Bay, but outside of an existing deep water channel, at a distance greater than 500 yards from the existing deep water channel for the security buffer, and north of the southernmost onshore alternative sites described in Section 10.5.1.2, was also eliminated from further consideration due to the need to undertake significant dredging to accommodate the anticipated draft of the LNG transport vessels and the proximity to population centers. The only other locations within the Bay wide enough to avoid significant impacts to vessel traffic when considering the applicable safety and security zones would be those located farther south than the proposed Terminal Site. Such locations would add significant length to the natural gas send-out pipeline, thereby increasing the potential environmental impacts associated with construction and decreasing the economic viability of the Project.

Based on the above considerations, AES concluded that an offshore terminal location, whether sited along the Mid-Atlantic seaboard or within the Chesapeake Bay, would not be a feasible alternative to the proposed Terminal Site.

10.5.1.3 Onshore LNG Terminal Sites

As noted above, AES determined that the only sites sufficiently proximate to the natural gas markets that the Sparrows Point Project is intended to serve, while providing a waterway having sufficient depth and capacity to accommodate LNG vessel traffic, would need to be located in the Delaware River or Chesapeake Bay regions. Upon further investigation, AES determined that the depth of the approach waterways in the Delaware River and the narrowness of the Delaware River shipping channel to populations centers effectively ruled out any alternative site location within that area. Accordingly, AES limited its search of alternative onshore sites to locations within the Chesapeake Bay.

<u>Alternative On-Shore Sites</u>

Within the Chesapeake Bay area, AES identified several alternative locations to the Terminal Site for further evaluation, including: (1) two sites near Cove Point, Maryland; (2) Greenbury Point; (3) Fishing Point and other sites within the Baltimore Inner Harbor; (4) Swan Creek immediately south of the Key Bridge; (5) Kent Island; and (6) an alternative Sparrows Point peninsula site

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[20] AES assumed a minimum safety and security zone of 500 yards around such offshore terminal facility. If the facility were placed within the existing deepwater channel the safety and security zone would effectively prohibit vessel traffic in the channel. However, vapor exclusion zones would need to be calculated to determine how far downwind natural gas vapors or a cloud could travel from an offshore LNG facility and still be flammable, which may be a greater distance than the assumed 500 yard safety and security zone.

(Mittal Steel site). Each of these alternative onshore site locations is discussed below. Figure 10.5.1.3-1 identifies the locations of the proposed alternatives.

The analysis was conducted using existing resource information available on United States Geological Survey (USGS) 7.5-minute series topographic quadrangle maps; Maryland Geographic Information System (GIS) data layers; other available federal, state, and county resource maps; recent high resolution aerial photography; and unmapped data. The analysis focused on an evaluation of proximity to population centers, route length, feasibility of using existing corridors, need for crossing existing transportation features, the presence of wetlands and waterbodies, threatened and endangered species and significant habitat, land uses and vegetation cover types, the presence of Federal and states lands, and several other special land uses. A tabular summary of this analysis is included within Table 10.5.1.3-2: Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project.

Locations for the AES Sparrows Point Project:

<u>Proposed Sparrows Point Site</u>

As compared to each of the alternative onshore sites, the proposed Terminal Site is located relatively distant – more than one mile – from the nearest residential community, but still within an industrially-zoned port area that is fully capable of supporting the facilities and vessel traffic proposed by AES (Figure 10.5.3-2). Significantly, the separation distance of over one mile is maintained along the entire LNG vessel transit route up to the Terminal Site. In addition, the proposed Terminal Site is capable of satisfying all federal safety and security requirements applicable to the design, construction and operation of LNG terminal facilities and transit of LNG vessels. AES is able to demonstrate site control within the timeframe necessary to submit its application and commence construction of the Project, and will be able to maintain such control during the operational phase of the Project. Construction of the LNG Terminal within an existing industrialized area will avoid and minimize the potential environmental impacts associated with the Project. Further, the relatively close access to an existing well-maintained, deep draft shipping channel will minimize potential impacts associated with additional dredging that is needed to accommodate the range of vessels being considered by AES for delivery of LNG to the proposed Terminal Site.

Finally, consideration was given to the environmental and economic feasibility of routing the Pipeline from the alternative LNG terminal sites to the intended interconnection points. The proposed Terminal Site, by comparison to the alternative sites considered, provides superior access to existing utility ROWs, and thereby would minimize the potential environmental impacts associated with construction of the Pipeline required to connect the LNG Terminal to both the local and the interstate natural gas pipeline grid. For these reasons, AES determined that the proposed Terminal Site at Sparrows Point, relative to any of the alternative terminal sites, would provide the most favorable location for the Project.

<u>Two Sites Near Cove Point, Maryland</u>

AES evaluated the area in the vicinity of the existing LNG terminal at Cove Point, Maryland to identify an alternative location that would satisfy its siting criteria. Specifically, AES was able to identify two locations north of Cove Point that have limited industrial zoning designations and for which the distance between the shipping channel and the shoreline is one mile or greater: (1) the existing Dominion Cove Point LNG terminal facility; and (2) the Calvert Cliffs Nuclear Power Plant. Figure 10.5.1.3-3 identifies the locations, zoning designations and key features (*e.g.*, residential areas and shipping channel) for Calvert Cliff's Nuclear Power Plant, and Figure 10.5.1.3-4 identifies the same for the Dominion Cove Point alternative.

The existing Dominion Cove Point LNG terminal site would not satisfy several of AES's screening criteria (Table 10.5.1.3-2: Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project). AES would be unable to maintain a distance of at least one mile between its onshore LNG storage tanks and the closest residential communities (the nearest residential communities are located less than one-third mile from the existing Dominion Cove Point LNG storage tanks). In addition, unless AES were to construct an offshore unloading platform similar to the existing Cove Point facility, along with all the accompanying environmental impacts associated with the construction and maintenance of such a structure, the final transit location of the LNG vessels would also be within approximately one-third mile from residential areas. The Cove Point unloading facility is approximately the same distance to residential areas as the onshore unloading facilities proposed by AES as part of the Sparrows Point Project. Finally, collocation of the Project adjacent to the Dominion Cove Point LNG terminal facilities also would result in greater potential environmental impacts as compared to the proposed Terminal Site because of the significantly longer length of the pipeline that would be required to reach the terminus point near Eagle, Pennsylvania, the absence of an existing utility corridor in this area through which the pipeline could be routed, and the need to clear undeveloped land to support the terminal facilities.

The existing Calvert Cliffs Nuclear Power Plant site is located approximately one mile from the closest residential communities, though any collocated LNG terminal facilities would need to be sited within this one-mile separation distance (Table 10.5.1.3-2: Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project). This factor fails to satisfy AES's site screening criteria. In addition, this site also would require the use of a significantly longer length of pipeline (147.7 miles required) and lacks availability of an existing utility corridor. In addition, Calvert Cliffs Nuclear Power Plant announced plans to expand their facility. The Board of County Commissioners (BOCC) for Calvert County voted to enter into an Agreement with Constellation Generation Group, LLC (CGG) that could add a third reactor at the Calvert Cliffs Nuclear Power Plant. Calvert Cliffs Nuclear Power Plant currently houses two nuclear reactors that came online in 1975 and 1977. The facility was originally designed for four reactors. Finally, AES does not anticipate that it would be able to obtain site control in this location within a reasonable and timely manner.

On the above bases, the two alternative sites located near Cove Point, Maryland were determined to be significantly less preferable than the proposed location at Sparrows Point.

<u>Greenbury Point</u>

AES evaluated the feasibility of siting its proposed LNG terminal facilities at Greenbury Point on the north side of the mouth of Severn River (Table 10.5.1.3-1: Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project). This alternative location was determined to be significantly less preferable to the proposed Sparrows Point location because of the proximity (approximately less than 0.5 mile) of Greenbury Point to the closest population centers (this site is zoned for residential use), the need to construct a significantly longer natural gas pipeline (107.5 miles required) to reach the determined terminus point near Eagle, Pennsylvania (thereby increasing the potential environmental impacts associated with construction of the Project), and the remote location off the Chesapeake deep water shipping route relative to the alternative site (greater than a three-mile distance), which would require a greater area affected by dredging. AES also determined that Greenbury Point's relatively close proximity to an existing Naval Air Station (1,100 feet to the west-northwest) and Naval anchor zones (4,200 feet to the west) likely could present potential conflicts with U.S. military installations and operations. Figure 10.5.1.3-5 identifies the location and key features of the Greenbury Point alternative site.

Fishing Point and Other Sites Within the Baltimore Inner Harbor

AES evaluated an alternative site in an existing industrialized area north of the Key Bridge at Fishing Point, which is situated on the north side of Curtis Bay. Figure 10.5.1.3-6 identifies this alternative site location and key site features.

AES determined that this site would be significantly less preferable to the proposed Terminal Site because transit of LNG vessels within the Baltimore Inner Harbor would have a greater impact on commercial and recreational vessel traffic and require substantially more dredging (Table 10.5.1.3-1: Comparison of Proposed LNG Terminal Location and Seven Alternative). Further, the Pipeline would need to be routed through highly-congested areas within the City of Baltimore (thus increasing potential landowner impacts), and the overall length of the Pipeline would be longer in order to reach the determined terminus point near Eagle, Pennsylvania (thus increasing construction-related impacts). Additionally, installation of the gas pipeline across the main shipping channel to the port of Baltimore at a depth that would avoid impact to maintenance dredging, potential expansions by the port, and shipping traffic during construction is considered technically not feasible and cost prohibitive. While the terminal would be located approximately 1.2 miles from the nearest residential communities, by necessity the turning basin would bring LNG vessels within 3,500 feet of the nearest residence. The factors describe above have eliminated the Fishing Point site from further consideration.

The area north of the Key Bridge were eliminated generally from further consideration because such sites were (1) occupied by BG&E facilities, (2) slated for future expansion by the Port of Baltimore, or (3) occupied or slated to be occupied by other commercial or industrial users. In other words, these alternative locations are not available.

Swan Creek

The Swan Creek site, which is located in an existing industrialized area south of the Key Bridge and across the deep water channel from the proposed site at Sparrows Point, *i.e.* south of Hawkins Point and north of Cox Creek, was determined to be significantly less preferable than the proposed Terminal Site at Sparrows Point for the reasons set forth below. Figure 10.5.1.3-7 identifies this alternative site location and key site features. Table 10.5.1.3-1: Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project summarizes the citing criteria of this alternative.

The alternative Swan Creek site is located less than one mile from the closest residential communities. At this location, AES would need to locate its proposed berthing facilities in an area that would require greater dredging to avoid potential interference with shipping traffic in the channel (in this area, the distance from the Brewerton Channel is approximately 1.2 to 1.3 miles, and water depth is more shallow than that along the Sparrows Point marine channel). Extensive filling of wetlands (approximately 6.3 acres required) also would be required to accommodate the LNG Terminal facilities, which may interfere with the Maryland Port Authority's long-term dredge disposal plan that is being implemented. This site would require construction of a longer natural gas pipeline (91.3 miles required) that either would have to be routed through highly-congested areas to the south and west, or would require crossing of the Patapsco River in order to follow a route similar to the proposed route for the Sparrows Point site. Even if the Pipeline were routed across the Patapsco River, the Pipeline would need to be installed at a depth and with a sufficient buffer on either side of the River to accommodate future deepening and widening of the River. Such a crossing likely would span several miles in length and could not be completed using horizontal direction drill methods because of its length and depth. If the crossing were completed using conventional methods, construction of this segment of the pipeline would have considerable potential impacts on commercial and recreational traffic, in addition to increased environmental impact. The Swan Creek site thus was considered to be a significantly less preferable alternative to the proposed Sparrows Point site.

Kent Island

AES evaluated an alternative site located on the north end of Kent Island on the eastern side of the Chesapeake Bay. Figure 10.5.1.3-8 identifies this alternative site location and key site features.

This site also was eliminated from further consideration because the site is located relatively close (approximately less than 0.5 mile) to the nearest residence, and the size of the existing industrial zoned area is not sufficient to accommodate the proposed LNG terminal facilities, meaning that AES would need to obtain an industrial zoning designation for adjacent land (Table 10.5.1.3-1: Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project). For these reasons, the Kent Island alternative was determined to be significantly less preferable than the proposed site at Sparrows Point.

Alternative Sparrows Point Site - Mittal Steel

AES investigated the possibility of siting its proposed terminal and berthing facilities at certain locations further south along the Sparrows Point peninsula, each of which currently is owned by Mittal Steel USA ("Mittal"). Figure 10.5.1.3-9 identifies this alternative site location and key site features. Table 10.5.1.3-1: Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project summarizes the citing criteria of this alternative. AES determined that it could not obtain site control in these locations in a reasonable and timely manner because of ongoing corporate strategies at Mittal and its parent company that affect site ownership. Specifically, Mittal acquired the property from International Steel Corporation (ISC) in 2005,[21] and has been working since that time to coordinate the Sparrows Point operation into the operations of the larger company. In early 2006, a new plant manager was appointed. Then, in June 2006, Mittal officials announced that it had begun to showcase the steel mill to potential buyers, believing that it might have to sell the plant for antitrust reasons arising out of a takeover fight for its biggest global rival, Arcelor SA. In July 2006, Mittal announced that it had successfully taken over Arcelor after a five month battle. On September 27, 2006, Mittal announced that it planned to sell another mill rather than Sparrows Point if it were to be compelled to dispose of a property located in the United States to settle antitrust issues; however, the Justice Department must sign off on which plant is sold and to what buyer.

Given the ongoing corporate activities at Mittal, the uncertainty as to the timing of the resolution thereof, and the uncertainty as to the timing of (or even any expression of interest in) negotiations with AES for site use or acquisition, AES would not be able to demonstrate site control as required by Commission regulations for submittal of its application.

In addition to the ongoing corporate strategies at Mittal, AES also understands that the State of Maryland is evaluating the feasibility of using a portion of the Mittal site for future dredged material placement activities in support of a long-term dredged material management plan and possible future marine terminal facilities for the Port of Baltimore. Such evaluation has been ongoing for more than 10 years. While dialogue with community, recreational, and environmental stakeholders to address a variety of issues is ongoing, no decision on this possible use of Sparrows Point is expected in the near future. Any decision to pursue Sparrows Point as a dredged material management project would initiate the multi-year NEPA process.

For the reasons provided above, location of the LNG Terminal and berthing facilities further south along the Sparrows Point peninsula is not considered to be a viable alternative for the proposed Project.

[21] ISC bought the site in 2003 from Bethlehem Steel Corporation (BSC) in a bankruptcy proceeding that was initiated by BSC in 2001.

10.5.2 Terminal Design Alternatives

10.5.2.1 Pier Designs

AES originally considered a pier design that would require installation of pipe cylindrical piles that would support a concrete deck and unloading platform. The pier would extend approximately 1,000 feet from the shoreline and would require additional piles for mooring and breasting dolphins to moor the ships. Upon review of public and agency comments and consideration of potential environmental impacts, the pier design was changed to utilize an existing structure, Pier 1, thereby eliminating the need for installation of additional piles for the pier or the breasting and mooring dolphins. The locations of the proposed (preferred) and alternate pier locations are shown on Figure 10.5.2-1. A more detailed description of the proposed pier design is included in Resource Report 1, *General Project Description*. A discussion of the relative merits of the alternate pier designs is set forth below.

<u>Preferred Design</u>:

Advantages associated with the preferred pier design and location includes the following:

- The preferred pier design location will dramatically reduce the quantities of dredge material. AES estimates that the total dredge quantity will be reduced by approximately 1.7 million cubic yards to approximately 3.8 million cubic yards from the Alternate Pier design, which translates to overall less potential environmental impact while dredging and greater economic viability.

- The existing pier structure will need only to be resurfaced and existing piles repaired. Additional piles into the water bottom will not be required; therefore, there will be no permanent bottom impact caused by driving piles for the pier or dolphins.

- Security buffers at Pier 1 provided by Pier 3. The existing Pier 3 essentially acts as a screen that prevents small craft from having access to the ships. The screen provided by Pier 3 also allows for better overall security of the ship while it is berthed.

- Environmental operating conditions are improved as this location provides for better shelter from environmental conditions, such as wind and wave, which ultimately increases the berth availability of this location.

- Cost effectiveness is enhanced due to reduced dredging and lower overall construction costs of building a pier from scratch.

- A significant amount of wet bottom will be re-established as AES will demolish and remove Pier 2 in order to accommodate the vessels on the northern side of Pier 1.

There also are certain real or perceived disadvantages associated with the proposed location of the LNG pier away from the location of the original design. Perceived disadvantages associated with the preferred design include the following:

- The preferred design is located closer (approximately 5,808 feet from the nearest residence in Turner Station) to residential populations than the Alternate Pier design; however, the distance is still in excess of the one-mile guidance used by AES in its site selection criteria.

The closest point of the turning basin associated with the proposed pier is located 4,950 feet from the nearest residence in Turner Station. The nearest residence in Turner Station to the bow of the LNG ship is 5,600 feet.

- Security control may be perceived to be lessened while ships are at the berth because the preferred location is closer to Pier 3, which is not anticipated to be controlled by AES. This concern is mitigated by the fact that the security control or potential threats are not likely to change based on the slightly closer distance. Also, it is expected that the entire Sparrows Point peninsula will be an ISPS port facility and subject to similar safety procedures used by the LNG terminal.

- The preferred pier location is closer to Bear Creek, which may have some impact on deep-draft recreational/commercial boats should these vessels be required to transit outside of the security zone while the LNG vessels are maneuvering. In conjunction with the USCG, AES will establish a fixed security zone around the marine side of the Terminal Site that will offer the maximum level of protection for the LNG Terminal and minimize the potential for impacts to commercial and recreational vessel traffic. At this time it is not anticipated the fixed safety/security zone will impact commercial and recreational traffic utilizing the Bear Creek entrance channel. However, the moving safety/security zone that will be established for loaded LNG ships may have a temporary impact on deeper draft recreational or commercial vessels during incoming maneuvering operations in the proposed turning basin depending on the size of the safety/security zone as determined by the USCG.[22] The incoming maneuvering operations are anticipated to last approximately 45 minutes based on real-time simulations performed for vessel transit evaluation from the Brewerton Channel to the dock at the LNG Terminal. Because the safety/security zone moves with the vessel, the potential disruption to deeper draft commercial or recreational vessel traffic transiting to or from Bear Creek (depending on the size of the zone as determined by the USCG) would be much less than the full transit time.

<u>Alternate Pier</u>: Pier located at the site in between Pier 1 and the Graving Dock

Advantages associated with the Alternate Pier design include the following:

- Location central to Terminal Site would allow for a shorter overall length of the unloading and vapor return lines. This would be an economic advantage.

- This design would have the pier located approximately 6,608 feet from the nearest residence in Turner Station than the preferred design. Because the preferred design maintains a separation distance greater than one mile, and there is no regulatory requirement providing for a specified separation distance, this advantage was not considered to be significant. The closest point of the turning basin associated with this alternative is located 6,000 feet from the nearest residence in Turner Station. The closest point in Turner Station to the bow of the LNG ship is 6,400 feet.

[22] The safety/security zone restrictions only apply when the LNG vessel is loaded. Thus, when the vessel departs from the LNG Terminal, no restrictions will apply.

- The Alternate Pier design contemplated removal of some of the finger piers along the shoreline. This would provide for establishment of additional wet bottom. Because the preferred design also contemplates the removal of approximately the same square footage by dismantling Pier 2 as the finger piers, this advantage is negated when comparing to the preferred design.

- Environmental operating conditions, such as wind and wave action, are generally favorable at this location, which ultimately increases the berth availability of this location, but they are slightly less favorable than the preferred location due to Alternate Pier's closer distance to more open water.

Disadvantages associated with the Alternate Pier design of the LNG pier include the following:

- The Alternate Pier location and design would require higher quantities of dredging than the preferred design (estimated quantities of dredging required, for this design, are 5.5 million cubic yards). Additional dredging would lead to additional bottom impact during construction from dredging, recycling process, temporary storage and transportation to final disposal area.

- Installation of a new pier as contemplated by the Alternate Pier design would require installation of new piles to support the pier. Approximately 340 piles with an expected permanent bottom impact of 3,060 square feet would be required for installation of the pier, platform and dolphins. This additional permanent bottom impact compares quite unfavorably to no bottom impact (or positive bottom impact if accounting for the removal of Pier 2) associated with the preferred design.

- Site access to the pier due to the location of the pier in the center of the Terminal Site is more difficult than the preferred design. Such location would require that most maintenance work be performed off of barges. Due to the central location of the alternate pier alignment and proximity to the flood wall and LNG tank area, AES would have to design an access road to the pier over the top of the flood wall and down to the pier elevation. Because there is less than half of the area to accommodate such an access way compared to the preferred design, the access way would need to be made very narrow in comparison. The narrow access way and rather steep incline would limit vehicle access to the pier from the shore. Therefore, the majority of the maintenance that would be necessary to perform on the pier systems would need to be performed by using a barge as a working platform. This would increase the overall cost of maintenance as well as duration of the maintenance period. Although the preferred pier layout does not totally eliminate the need to perform barge maintenance on some pier systems, the design greatly enhances the ability to access pier systems from the shore using more conventional work equipment due to the width of the access way and gradual elevation change from the site road ways to the pier.

- The cost of the additional dredging and associated reclamation as well as the capital cost for this installation makes this option the more expensive option considered.

10.5.2.2 Regasification

<u>Preferred Design</u>

The preferred option for regasification methods involves the use of steam from a boiler to warm an intermediate High-Temperature Fluid (HTF) that will be circulated through a shell and tube vaporizer used to vaporize the LNG.[23] A schematic diagram of this process is shown in Figure 10.5.2.2-1. Advantages inherent in this design include the following:

- Operation. The preferred design allows ease of operation and transfer of heat into the LNG at relatively high efficiencies.

- Emissions for this process can be easily controlled and minimized to the lowest achievable levels using existing proven technology.

- The preferred design allows for the integration of other heat sources into the vaporization loop with little or no impact on the current operation. Additionally, this system allows for the addition and integration of the combined cycle cogeneration Power Plant, presently being considered by AES, which will produce power using the natural gas that would have been used in the boilers. Natural gas consumed in the Power Plant produces waste heat that may be used in the LNG vaporization cycle and generate needed power for the area thereby improving the overall efficiency of both operations with little to no increase in overall environmental impacts. The Power Plant concept fits well with Maryland's recently passed Healthy Air Act, which mandates reductions in carbon dioxide (10 percent cut by 2018), sulfur dioxide (83 percent cut by 2010 and 90 percent by 2015), nitrogen oxides (67 percent cut by 2010 and 80 percent by 2015), and mercury (90 percent cut by 2010). Natural gas plants typically emit 43.7 percent less carbon dioxide, 99.6 percent less sulfur dioxide, 79.8 percent less nitrogen oxide, and 99.7 percent less particulates than coal plants. As more electric power is needed in congested areas of growing demand (such as this area of Baltimore), clean-burning options such as summarized here are environmentally preferred over options with higher air emissions. Accordingly, whether the potential Power Plant displaces existing power generating sources or meets a portion of the increasing demand in the area, net air emissions will be less than would be experienced were a generating option with higher air emissions to fulfill that same demand.

- Intermediate fluid loop. There is an intermediate loop of HTF that provides for additional protection from freezing of the vaporizers and also provides another system barrier between the LNG and other plant processes.

There also are certain disadvantages associated with the use of steam from a boiler to warm an intermediate fluid that would be circulated through a shell and tube vaporizer used to vaporize the LNG. Perceived disadvantages include the following:

- Efficiency. Initial efficiency of this operating cycle might be lower than those presented as alternates; however, the longer term integration with the combined cycle facility far outweighs any options presented in terms of overall emissions and cycle efficiencies.

[23] The HTF is expected to be a mix of ethylene glycol.

- Ease of operation. The preferred design is slightly more complicated that the other alternatives presented but not so much that it creates an impediment to overall plant safety and reliability.

Emissions are presented below in table 10.5.2-1 for comparison.

Table 10.5.2-1 Emissions Associated with Alternative Regasification Methods

Option #	**Technology**	**Emission Controls**	**Annual NOx Emissions (TPY)**
Preferred	Steam Boilers	Low NOx Burners, Flue Gas Recirc, SCR	23
1a	Submerged Combustion Vaporizers	Conventional NOx Design	167.5
1b	Submerged Combustion Vaporizers	Low NOx Burners	54
2a	Gas Fired Heaters	Conventional NOx Design	175.5
2b	Gas Fired Heaters	Ultra Low NOx	56
3	Sea Water Vaporization	N/A	0*

* Due to cold seawater temperature, supplemental heating would be required during cold months of the year; this table does not reflect NOx emissions associated with impacts from these differing emissions.

<u>Alternative 1 (a & b)</u>: Submerged Combustion Vaporizers (SCV)

This system uses a burner to discharge heat from combustion directly into a water bath. A schematic diagram of this process is shown in Figure 10.5.2.2-2. The water bath is the medium to transfer heat to the submerged LNG heating coil. Once the exhaust gases have transferred their heat to the water bath they are exhausted out the stack. The water bath continually transfers heat from the warmed water to the heating coil there by heating the LNG and causing a phase change from liquid to gaseous state. The use of SCV offers certain advantages and disadvantages as set forth below. Considering both sides, AES has determined that the disadvantages outweigh the advantages when compared to the preferred method of vaporization.

Advantages:

- Simple operation. Use of the SCVs allows for easy integration with the cycle to vaporize LNG. As a result, operation of these units is fairly common in the LNG industry.

- High efficiency. The SCVs have a relatively high efficiency rating that is slightly greater than that available from the preferred option.

Disadvantages:

- The environmental impacts associated with the SCVs are greater due to the fact that overall air emissions cannot be controlled as well as in the case of the preferred option using existing proven technology. This would lead to an overall increase in annual air emission levels at the Terminal Site to vaporize the same quantity of gas.

- The discharge system generates an acidic waste stream that needs to be neutralized prior to discharge, which increases overall maintenance requirements on the equipment.

- Integration. The system does not integrate with The AES Corporation's potential future plans to build a cogeneration facility, which means that the SCVs will be required to vaporize gas regardless of whether or not the cogeneration Power Plant is operating. The LNG Terminal will not be able to take advantage of waste heat from the cogeneration Power Plant cycle. This would increase overall emissions on an annual basis and reduce efficiency overall.

<u>Alternative 2 (a & b)</u>: Gas Fired Heaters (GH)

This system uses a closed loop circulating HTF system for transfer of heat from a gas fired heater directly to the HTF. A schematic diagram of this process is shown in Figure 10.5.2.2-3. The HTF is circulated through the vaporizer where it transfers its heat to the LNG. The LNG enters the vaporizer in liquid form and due to the heat transferred from the HTF system, changes state and leaves the vaporizer in gaseous form. The use of GH offers certain advantages and disadvantages as set forth below. Considering both sides, AES has determined that the disadvantages outweigh the advantages when compared to the preferred method of vaporization.

Advantages:

- Simple operation. Use of the GHs allows for easy integration with the cycle to vaporize LNG. As a result, operation of these units is fairly common in the LNG industry.

- High efficiency. The GHs have a relatively high efficiency rating that is slightly greater than that available from the preferred option but less than the SCVs (Alternative 1).

Disadvantages:

- The environmental impacts associated with the GHs is greater due to the fact that overall air emissions cannot be controlled as well as in the case of the preferred option using existing proven technology. This would lead to an overall increase in annual air emission levels at the Terminal Site to vaporize the same quantity of gas.

- Integration. Because the system will operate at a higher temperature, the system does not integrate easily with AES's potential plans to build a cogeneration facility. This means that the GHs will be required to vaporize gas regardless of whether or not the cogeneration Power Plant is operating. The LNG Terminal would not be able to take advantage of waste heat from the cogeneration cycle, which would increase overall emissions on an annual basis and reduce efficiency overall.

Alternative 3: Direct Seawater Vaporization

This system uses an open loop which requires water to be drawn directly from the Chesapeake Bay, circulated through a shell and tube heat exchanger where heat is transferred from the relatively warm water to the colder LNG, and then returned back to the Bay at a much cooler temperature. A schematic diagram of this process is shown in Figure 10.5.2.2-4. The LNG enters the shell and tube heat exchanger in liquid form and due to the heat transferred from the water system, changes state and leaves the vaporizer in gaseous form. The use of a direct seawater vaporization system entails certain advantages and disadvantages as set forth below. Considering both sides, AES has determined that the disadvantages outweigh the advantages when compared to the preferred method of vaporization.

Advantages:

- Operation of this type of system is the simplest of all revaporization alternatives. Under this method, seawater would be withdrawn from the Patapsco River, run through a shell and tube heat exchanger or an open rack vaporizer where the LNG would be vaporized, then discharged back to the Patapsco River at a lower temperature.

- There are no combustion emissions from this process other than for the power required to run the pumps and for the periods during the colder months where vaporization would need to be supplemented by other means of heating (e.g., SCVs, GHs).

Disadvantages:

- The volumes of seawater that would be required to be pumped out of the Patapsco River and then returned substantially cooler than their original condition would result in significant impacts to aquatic life forms. For this reason alone, this option was considered to be the least desirable of all presented.

- The overall available heat from the Patapsco River is limited to the warmer periods of the year; therefore, supplemental heating would be required during winter months from additional equipment installed at the facility such as SCVs or boilers to meet supply commitments of the facility. This unnecessary duplication of equipment would result in economic waste.

- The National Oceanic Atmospheric Administration National Marine Fisheries Service generally considers the aquatic impacts of this vaporization method unacceptable for locations within estuaries, due to the demand for high volumes of water and the associated impingement and entrainment impacts to aquatic life.

10.5.2.3 Dredge Method Alternatives

Construction of the proposed LNG Terminal will require offshore dredging to widen and deepen the existing approach channel and create a turning basin, both of which are necessary to safely accommodate the range of LNG ships intended to be used to deliver LNG to the Terminal Site. Dredging of the main approach channel is expected to be completed primarily with the use of mechanical clamshell dredge or, if and where required based on sediment composition and quality, an environmental bucket technology. These same techniques will be used for dredging the turning basin that will be located between the point where the approach channel reaches the floating dry dock, the graving dock and the berthing area. Limited near shore areas will be excavated by backhoe dredge.

AES evaluated the use of hydraulic dredging as an alternative to its proposed dredge methods. The use of hydraulic dredging was determined to be less preferable than the proposed methods due to several factors, including the increased volume of throughput, the large dewatering area required, decreased rate of dewatering due to increased mixing of dredge material in water, greater processing time, and greater potential environmental impact due to suspension and dispersion of sediment associated with the use of hydraulic dredging. As compared to hydraulic dredging, the use of clamshell or bucket dredging will involve a lower throughput volume, smaller dewatering area due to the use of barges to complete some dewatering, and a smaller upland area required to complete the process and shorter overall processing time. AES's proposed dredging method therefore was determined to be preferable to the use of hydraulic dredging.

10.5.2.4 Dredge Disposal Alternatives

AES evaluated four potential alternatives to the use of a dredged material recycling facility (DMRF) to handle dredge material, including disposal of dredge material at an approved offshore location, upland disposal of dredge material at a location other than the Terminal Site, disposal at existing fill site(s) for which expansion is planned, and innovative reuse as statutorily defined in Maryland law. A summary table (Table 10.5.2.4-1) of key elements of the disposal options that are described in detail below is attached, and includes potential final disposal sites, apparent capacities, disposal methods and relative costs. AES determined that the alternative of innovative re-use was preferred over the other alternatives.

A. Offshore Disposal

AES has evaluated the feasibility of offshore disposal from the standpoint of sediment quality relative to other dredge management projects performed in the Port of Baltimore and Sparrows Point area for purposes of determining if offshore disposal may be viable for all or a portion of the dredge material management.

Sediment sampling has been performed in the area where the proposed dredging would take place. The sampling was performed during the period of May to June 2006, and the results are summarized in Section 2.4 of Resource Report 2, *Water Use and Quality*. The results show that sediment quality in the areas subject to dredging is comparable in chemical quality to other sediments that have been dredged from the Port of Baltimore for disposal in the area's Contained Disposal Facilities (CDFs: e.g. ,Hart-Miller Island; Cox Creek) and ocean disposal sites (e.g., Dam Neck Ocean Disposal Site). Environmental contaminants are present in the upper portion of the sediment profile comprising primarily polycyclic aromatic hydrocarbons (PAHs – compounds formed by incomplete combustion of carbon-containing fuels such as wood, coal, diesel), and heavy metals. The sample results show that these compounds tend to decrease in concentration with depth and were generally not detected in sediments below approximately 10 to 15±

feet or at the planned dredge depth of 45 feet below mean sea level (the new mudline surface that would remain once dredging has been completed).

Ocean placement at a designated ocean site could be a viable placement location for the relatively clean dredge material located below the shallow sediments containing typical Port of Baltimore contaminant compounds. Approval of such location would be subject to EPA and Army Corps of Engineers (ACOE) approval, and would require evaluation consistent with the ACOE *Dredging and Dredge Material Placement* manual.

AES has also determined in the course of dredge evaluation that the use of an approved offshore disposal site – assuming that sediment quality is determined to be acceptable for placement at an EPA approved offshore site - would be less preferable than the use of the DMRF. This is due to the potential time required for vessels to travel to and from the offshore placement site, taking into consideration potential weather and other delays, the nature of and timeframe required to obtain authorizations necessary to place the dredge material at an offshore location. Relative cost associated with this offshore disposal is also unknown and would be dependant on vessel capacity and shipping distance to an approved disposal location. However, given the results of the sediment sampling for the lower layers proposed to be dredged, this alternative might still prove practical if used in conjunction with the DMRF for dealing with the relatively large volumes of cleaner material.

B. Upland Disposal

The Commission Staff requested that AES evaluate the potential for upland disposition of dredge material if it is determined that some of the contaminated dredge material cannot be disposed of in the manner otherwise proposed herein (i.e., innovative reuse and/or open ocean placement). Comparison of the sediment quality anticipated from the proposed dredge area for this project to sediment historically removed for maintenance dredging from the Patapsco River and Bear Creek area indicates the sediment quality is consistent. Historically, sediment dredged from the Patapsco and Bear Creek has been contained at the Hart-Miller Island site or placed at the Dam Neck Ocean Disposal Site. It is therefore anticipated that upland disposal would be dependant on finding a facility or facilities with capacity to accept the material either unprocessed as a solid waste, or processed as a useable product. Given the relatively clean quality of the sediment at depth, disposition of this clean portion of the dredge material at Hart-Miller Island, or other CDFs in the area, or solid waste disposal facilities, would not be a compatible use of capacity of those facilities, unless the material were appropriately dewatered and used for daily cover or capping. It is therefore assumed that the volume of dredge material that may be subject to contained upland placement would be only a portion of the total dredge amount. An approximate percentage calculation, based on the portion of potential dredge volume represented by the shallow and intermediate dredge material samples obtained and analyzed, as reported in Resource Report 2, *Water Use and Quality*, relative to the total dredge depth indicates these samples represent from 30 percent to 60 percent of the depth range of total dredge depth (i.e. where the sample for 0 to 10 feet depth was obtained from a location where dredging will remove 30 feet of sediment, the samples represent 33 percent of the depth range and therefore approximately 33 percent of the final dredge volume). Therefore, it is reasonably assumed that sediment that may be subject to upland disposal would be limited to 30 percent to 60 percent of the total dredge volume.

Clean Earth Dredge Technology Inc. (CEDTI) is working with AES on dredge management options for the project. CEDTI has worked closely with numerous regional governmental and regulatory agencies to develop and implement programs for appropriately stabilized dredged sediments for upland placement. Examples of these agencies include the New Jersey and Pennsylvania Departments of Environmental Protection, the NJ Department of Transportation, Office of Maritime Resources, the Pennsylvania Bureau of Abandoned Mine Reclamation, the New York State Department of Conservation, and the Port Authority of New York & New Jersey. This experience has provided CEDTI significant experience with the range of research, development, and implementation of treatment and placement options for contaminated dredged sediments in the region. CEDTI has, in bench-scale and full-scale field operations, applied Solidification/Stabilization technology to numerous dredging projects, rendering the dredged sediments suitable for upland placement.

For purposes of this evaluation, the alternative upland disposal methods assumed to apply to contaminated sediments that could not be processed, stored and then sold from the facility, would be reclamation and remediation of an abandoned mine facility, such as the Bark Camp Mine Complex, an abandoned coal strip mine located in Pennsylvania (a CEDTI project), or similar mine stabilization/reclamation in Pennsylvania and/or Maryland. The Bark Camp Mine has approximately six to ten million cubic yards of capacity required to complete reclamation and has been approved for acceptance of stabilized contaminated dredge material, and could comprise an upland placement site option for processed dredge material. The states of Pennsylvania and Maryland also have significant acreage requiring reclamation beyond the capacity present in the Bark Camp site. The stated goal of the Maryland Abandoned Mine Reclamation Program is to promote the reclamation of all abandoned mined areas in Maryland that have been left in an inadequately reclaimed condition and continue to endanger the health or safety of the public, degrade the quality of the environment or diminish the beneficial use of land and water resources. Land affected in Maryland is estimated at approximately 9,500 acres of land and 450 miles of streams that were impacted by surface and underground coal mining prior to State and Federal mining and reclamation regulatory programs.

AES determined that the use of an upland disposal site would be less preferable than the use of a dredge material processing facility at the Sparrows Point facility for processing; storage and sale/shipment to end users. See discussion below relative to the preferred DMRF alternative. This is due to the difficulty anticipated in identifying one or few sites nearby that could accept the volume of dredge material, the transportation requirements necessary to access an upland site, the need for unloading and additional processing once the dredge material is delivered to an upland site, and the nature of and timeframe required to obtain authorizations necessary to dispose of the dredge material at an upland location. Such disposition options are technically feasible, but would be difficult to manage in a timeframe consistent with the project. Cost of such an alternative is currently unknown, and would be dependant on cost of use or establishment of a stabilization plant facility at the mine location (such as Bark Camp), haul distance, and capacity available.

C. Disposal at a Fill Site

AES evaluated the feasibility of disposing of dredge material at the existing Hart-Miller Island dredged material containment facility in the Port of Baltimore area, and determined that the disposal facility currently does not have capacity available to handle the dredge material associated with the Project. While other fill sites in the general vicinity of the Project are planning to expand capacity in the future, AES understands that these capacity expansions will be limited to current or planned projects being undertaken by the Maryland Port Administration and other marine terminals in the Port of Baltimore and, thus, the expansions are not considered to be available or sufficient to handle the additional dredge material associated with the Project, especially when the annual capacity of any existing or planned placement site is considered[24]. For this reason, existing and planned dredged material placement facilities intended for material dredged from the navigational channels in the Chesapeake Bay outside of the Baltimore Harbor are not available to this material.

The State of Maryland has a public participation process as part of its Dredged Material Management Program. That process undertook a multi-year effort to identify and recommend options available for a long-term (20 years) plan for managing material dredged from the Baltimore Harbor channels. Known as the Harbor Team, community representatives and other stakeholders came together to consider options for managing up to 1.5 million cubic yards annually of harbor dredged material. Five hundred thousand cubic yards is the average amount of material generated from the maintenance of existing channels. The additional one million cubic yards allows for new dredging projects in the harbor. Options to accommodate this quantity of material over the 20-year period led to several site specific placement (containment facility) recommendations, as well as a recommendation for the innovative reuse of meaningful quantities of dredged material by 2023. The amount of material likely to be generated by the AES project exceeds what was planned for in the State's public process. AES understands that any expectation that the State's existing, planned, or proposed containment facilities will be unable to accommodate dredged material from the Sparrows Point Project

D. Innovative Re-use

The innovative re-use alternative would involve constructing an upland dredged material processing facility adjacent to the existing waterway at the Terminal Site (see Section 1.5.1.2 of Draft Resource Report 1, *LNG Terminal Offshore Construction* describing dredge plan and recycling facility layout). A 10,000 cubic yard per day DMRF would occupy approximately five acres of upland property within the boundaries of the Terminal Site. The processing facility would consist of duplicate (parallel) processing systems including hoppers, conveyors, pugmills for mixing additives, and stacking equipment. Emissions from each pugmill and additive delivery system would be

[24] A statutory requirement for material dredged from within the Baltimore Harbor, as determined by an imaginary line between North Point in Baltimore County and Rock Point in Anne Arundel County, is that it be treated as contaminated material and disposed at a contained disposal facility, regardless of chemical quality of the material to be dredged. Contained disposal is not required if the material is beneficially reused or processed for innovative reuse.

equipped with and controlled by separate baghouse dust-collection devices. Existing site roadways would be used to transport the processed dredged material from the pugmill processing system to the temporary Processed Dredged Material (PDM) storage area. The temporary PDM storage area would consist of an approximately 10-acre area covered by bituminous paving or lined with a 10-mil HDPE liner covered by 6- to 12-inches of existing site soil or imported soil. A scale house and truck scale would be located adjacent to the temporary PDM storage area for weighing of the outbound shipments of the PDM product upon sale. Existing site roadways or railroads will be used for outbound shipments of the PDM product.

The recycling facility area and temporary PDM stockpile area would be graded as necessary and paved with bituminous concrete, and equipped with stormwater management controls tied to existing facilities for stormwater management (note that the existing Sparrows Point facility routes and manages stormwater for the exposed land area of the facility through several permitted outfalls associated with its operations). AES would occupy similar land area and would pursue stormwater permits through either the Maryland Industrial Stormwater Permit program (appropriate to the industrial code applied to the DMRF) or permitted discharge under a site-specific National Pollutant Discharge Elimination System (NPDES) permit to be applied for from the State of Maryland – see Resource Reports 2 and 13 relative to stormwater management, testing, and permitting to be associated with the terminal and DMRF site. [DR2 No. 45] After civil work is completed, the DMRF would be erected at the site. All components of the processing systems would be fabricated off-site and delivered via truck to the construction site. Operation of the DMRF would occur during the LNG Terminal construction phase of the Project. Processing operations would commence following construction of the DMRF and simultaneously with the commencement of dredging operations.

The use of the DMRF would enable AES to manage the dredge material at an upland location adjacent to the dredge site, and stockpile processed material until it is sent to market by truck, rail or ship. This method also could be scaled up or down to accommodate the timing and quantity of the dredge material management needs during the dredging phase of the Project, for example, to allow for continuous processing of the dredged material even when the dredging is limited to certain windows as a function of the permit.

10.6 Pipeline Alternatives

AES took two different approaches to its review of pipeline alternatives. First, AES evaluated natural gas transmission alternatives to its proposed Pipeline vis-à-vis different delivery points or methods for the LNG upon its receipt at the LNG Terminal. Next, AES evaluated route alternatives between the Terminal Site and the proposed terminus point in Eagle, Pennsylvania.

10.6.1 Delivery Alternatives

AES evaluated five natural gas transmission alternatives to its proposed Pipeline, including (1) an alternative interconnection point to the proposed interconnections near Eagle, Pennsylvania, (2) interconnection solely with the existing Baltimore Gas & Electric Company (BG&E) natural gas distribution system, (3) use of truck and rail methods instead of a natural gas pipeline to transport LNG from the terminal, (4) combined use of a single interconnection with the existing BG&E system and truck and rail transport of LNG from the LNG Terminal, and (5) connection only with the Columbia Gas pipeline system. None of these pipeline system alternatives is considered to be a viable alternative to the proposed Pipeline for the following reasons.

AES first considered whether an alternative final interconnection point other than the proposed interconnections near Eagle, Pennsylvania would better serve the intended purpose of the Project. Because the Project is expected to be a high load factor facility, one of the main concerns over the final interconnection point is access to both substantial throughput and natural gas storage. In order to maximize access to markets and storage in the Mid-Atlantic Region, interconnection with the three existing Mid-Atlantic Region interstate pipeline systems near Eagle, Pennsylvania is necessary. Further, as noted in Section 10.3.2, connection into the major interstate natural gas transmission lines that pass through the Mid-Atlantic Region (Transco, TETCO, and Columbia) at any other locations further south than Eagle, Pennsylvania would require expansions of the existing lines to move the incremental gas to the market segment and significant additional environmental impacts, including an additional three to five crossings of the Susquehanna River, and operating impacts associated with those expansions.

AES next evaluated the feasibility of connecting solely with the existing BG&E natural gas pipeline system. While this system alternative would allow local consumers to avoid certain transportation costs associated with existing natural gas supplies transported from the Gulf of Mexico and other regions in North America, interconnection with the BG&E system alone would essentially reduce the function of the LNG Terminal to an oversize peak-shaving facility, thus making the required investment in terminal and marine facilities economically infeasible. BG&E already has sufficient peak-shaving capacity for its system at Spring Gardens in Baltimore, Maryland, and displacement of BG&E's entire natural gas load was not considered to be viable (the highest daily natural gas delivery in the BG&E system was approximately 0.8 bscfd for January 23, 2003; the average is significantly less). This system alternative not only would be commercially impractical, due to the costs of the Project compared to the projected quantity of deliverable natural gas, but would fail to provide a new incremental supply of natural gas to markets in the entire Mid-Atlantic Region, which is the key component of the overall purpose of the Project.

AES also considered the feasibility of using truck and rail transport to distribute LNG from the proposed LNG Terminal. In certain areas of the country, particularly the Northeast, small quantities of LNG are transported by truck to outlying areas and to and from peak shaving storage facilities. These outlying areas typically are located in relatively close proximity to the LNG Terminal and one another, resulting in relatively short truck transport distances. This same situation does not exist in the Mid-Atlantic Region. In addition, there currently is no commercial scale rail transport of LNG cargo. For these reasons, truck and rail transport on the scale necessary to support the take-away capacity of the proposed LNG Terminal was determined to be impractical and no further consideration was given to this system alternative.

A combination of truck and rail transport of LNG to markets in the Mid-Atlantic Region and a single interconnection locally with the existing BG&E natural gas distribution system was determined not to be a viable transmission alternative to the proposed Pipeline because this alternative would not be sufficient to support the take-away capacity of the proposed LNG Terminal to interconnections with the pipeline grid serving the Mid-Atlantic Region, and the use of rail and truck transport, as discussed above, is not considered to be commercially viable, since there currently is no commercial scale rail transport of LNG cargo for the Project Area.

Finally, AES also evaluated the feasibility of connecting to the existing Columbia Gas Line 1278 pipeline system just outside of Baltimore. While this transmission alternative would reduce the required length of send out pipeline required, this transmission alternative was found to be unacceptable as Columbia's system was described as having insufficient capacity to move the volume to the market and replacing this line would have the same or greater impacts than the Project plus interruption in service during the construction period.

10.6.2 Route Alternatives

The proposed route for the Pipeline generally parallels rights-of-way for existing highways, overhead electric transmission lines, and pipelines. In considering alternatives to the proposed Project to determine whether it might be possible to reduce the human and environmental impacts, AES evaluated alternative pipeline routes. Alternatives that were considered include four major route alternatives and numerous route variations. Figure 10.6.2-1 identifies the location of the proposed route for the Pipeline. As proposed, the route consists of four main segments:

- The proposed route exits the former Sparrows Point Shipyard and steel mill property and travels north to northeast for approximately two miles (MP 0.0 to 2.0);
- For approximately six miles (MP 2.0 to 8.0), the proposed route follows Route I-695 in a north and northwest direction, except for minor deviations necessary to avoid highway interchanges;
- Near the Back River crossing, the proposed route heads north to northeast and follows a BG&E overhead transmission corridor for approximately 24.5 miles (MP 8.0 to 32.5); and
- At the intersection with the right-of-way (ROW) for an existing Columbia pipeline, the proposed route heads northeast and generally parallels the existing pipeline ROW for approximately 54 miles (MP 32.5 to 87.6) to its terminus near Eagle, Pennsylvania.

AES applied several screening criteria to identify a proposed route between the Terminal Site and the interconnection points near Eagle, Pennsylvania. Principal among its route screening criteria were the desire to maximize use of existing ROW either to avoid or to minimize to the maximum extent possible construction-related impacts to the environment, landowners and other stakeholders, and to ensure the technical and economic feasibility of constructing the Pipeline. Although not the only criterion to be used in route selection, the preference towards the use of existing corridors is an industry standard and consistent with 18 CFR §380.15, which concerns siting and maintenance requirements for pipeline construction. Furthermore, this criterion is consistent with the objectives of most regulatory agencies, including the ACOE and the Commission. Using the standard screening criteria specified by the Commission in its guidance, AES identified four major route alternatives to the proposed route, which included following existing ROW and greenfield construction.

AES assessed each route alternative using a 100-foot wide corridor centered on the proposed alignment for the majority of the constraints. The analysis was conducted using existing resource information available on United States Geological Survey (USGS) 7.5-minute series topographic quadrangle maps; Maryland Geographic Information System (GIS) data layers; other available federal, state, and county resource maps; recent high resolution aerial photography; and unmapped data. The analysis focused on an evaluation of route length, feasibility of using existing corridors, need for crossing existing transportation features, the presence of wetlands and waterbodies, threatened and endangered species and significant habitat, land uses and vegetation cover types, the presence of Federal and states lands, and several other special land uses. A tabular summary of this analysis is included within table 10.6.2-1. AES also provided briefings to senior personnel of Maryland State agencies responsible for managing federally funded highways concerning routing that traversed federally funded highways, which are Interstate 95 and 695. Documentation of the briefings is included within Appendix B.

The following provides a summary of AES's initial screening level analysis of the four route alternatives.

10.6.3 Major Route Alternatives

10.6.3.1 Dundalk West Alternative

The Dundalk West Alternative would deviate from the proposed route at North Road (approximate MP 0.8), and follow an existing roadway for approximately 1.2 miles before crossing Bear Creek (Figure 10.6.3-1). The Dundalk West Alternative is then routed along an electric utility corridor through a densely populated area of Dundalk heading north for approximately 4.8 miles. The route would then rejoin the proposed route at MP 8.0.

While the Dundalk West Alternative is approximately one mile shorter, this alternative presented several disadvantages. Specifically, this alternative would impact a greater number of waterbodies and wetlands, as well as impact more historic resources and residential properties. A tabular summary of this analysis is included within Table 10.6.2-1. Additionally, the Dundalk West Alternative would be located through the Dundalk residential neighborhood and encroach near to several schools. While these latter considerations would not rule out this alternative by themselves, such proximity would cause greater disturbance to nearby or adjacent residents and necessitate specialized construction techniques in the more constrained areas. The public perception of locating another pipeline in an already crowded corridor is another negative aspect associated with this alternative.

Additionally, special construction techniques, including potentially Horizontal Directional Drilling (HDD), would be required to cross Bear Creek. In addition, some restrictions due to existing utilities and bridge structure would push alignment further to the north and potentially cause additional impact to Cheekwood Park and the associated wetlands to the west side of crossing. Congested areas near schools and businesses would require restricted workspace and potentially a compressed / limited construction period in order to minimize potential interference with local businesses and schools. Because the ROW is extremely congested with other utilities, it could require an extensive effort to uncover and locate existing utilities and potentially require hand digging certain areas to avoid interference with those utilities adding time and cost to this overall routing.

10.6.3.2 Western Corridor Alternative

The Western Corridor Alternative, would deviate from the proposed route after the Back River crossing (MP 9) and head north for approximately 21.0 miles along a northern-trending, two-tower BG&E powerline corridor (Figure 10.6.3-2). Shortly after it crosses the Baltimore and Harford County line in Harford County, Maryland, the alternative route would turn to the northeast and closely parallel an existing pipeline corridor, rejoining the proposed route at MP 32.5.

While the Western Corridor Alternative is located almost entirely within existing corridors and would result in substantially fewer impacts to wetlands, the Western Corridor Alternative presented several disadvantages from a constructability standpoint. A tabular summary of this analysis is included within Table 10.6.2-1. In summary, this existing corridor is highly congested with utilities, including two powerline lattice tower alignments and one to two existing pipelines. The ROW for this segment of the alternative route also would be located closer to more densely populated areas than would the proposed route, meaning that pipeline construction activities, while temporary, nevertheless would impact more landowners than would construction activities along the right-of-way for the proposed route.

There are several areas along this route where houses, fences and sheds are built right up to the corridor. Additionally in these areas there are several buried utilities. All of these items lead to a constricted reduced work space, potentially requiring special construction techniques including exposing existing utilities and shoring them up to avoid damage during installation of our pipeline (much of this may require hand digging to accomplish), reduced working hours to avoid additional impact to businesses and residential neighborhoods. This would lead to a greater overall construction time, cost and associated impacts. Additionally, near the Gunpowder Falls State Park crossing, this would require an HDD but the space for performing that HDD is constricted by residential housing, electric utility lines and substations at the south side of the park. This would be an extremely difficult crossing due to the obstacles in this area.

10.6.3.3 SR 136 Alternative

The SR 136 Alternative, would deviate from the proposed route at the intersection with the overhead transmission corridor and I-95 at approximate MP 19 (Figures 10.6.3-3). The alternative route would traverse northeast along I-95 for approximately 8.5 miles, and then turn north onto SR 136. For 13.6 miles, this alternative route would parallel, but not be adjacent to, SR 136 until rejoining the proposed route at approximate MP 40.0 at the existing Columbia pipeline ROW.

While wetland and waterbody impacts are similar and this alternative crosses significantly less steep terrain, SR 136 Alternative was determined to be less preferable than the proposed route. The alternative impacts a greater number of historical properties. A tabular summary of this analysis is included within Table 10.6.2-1. As compared to the proposed route, this alternative would impact a greater number of residential properties and would necessitate a substantial length of new right-of-way along the portion that parallels SR 136. This alternative route also would impact historic resources to a greater extent than would the proposed route by traversing the Finney House Historic District in Churchville, Maryland, and by traversing considerable Rural Legacy District area prior to reaching the pipeline corridor.

The majority of this route would require close coordination with the Maryland Department of Transportation (MDOT) along the I-95 corridor, and would require additional construction safety requirements to construct due to passing traffic. This coordination and the addition of collision trucks would potentially lead to additional time to construct due to restricted hours of construction imposed by the MDOT (need to avoid rush hour periods), and possibility of delays if approved vehicles were not available. This would lead to additional time, cost and related potential impacts. Additionally, along SR 136, there are several areas where construction techniques would require reduced CROW due to proximity of road and other utilities along side of the road. To avoid impact to local businesses and residences it is expected that time of day restrictions would be imposed that are more restrictive than much of the preferred route through this area. All these would lead to extended construction time, cost and overall increase in associated impacts.

10.6.3.4 US I-95 & Greenfield Alternative

The US I-95 & Greenfield Alternative would deviate from the proposed route at the intersection with the overhead transmission corridor and I-95 at approximate MP 19 (Figure 10.6.3-4). US I-95 & Greenfield Alternative would head north to northeast and follow I-95 for approximately 20.0 miles. At this point, the alternative would divert from I-95 and traverse 13.8 miles in a northerly direction across new right-of-way. Shortly after the pipeline crosses U.S. 1 in Harford County, Maryland, this alternative route would reach Columbia pipeline, rejoining the proposed route at approximate MP 40.0.

While this alternative crosses significantly less steep terrain, the US I-95 & Greenfield Alternative was determined to be less preferable than the proposed route. The alternative impacts a greater number of wetland and waterbodies and impacts a greater number of historical properties. A tabular summary of this analysis is included within Table 10.6.2-1. As compared to the proposed route, US I-95 & Greenfield Alternative would also impact a greater number of residential properties and would require over 13 miles of greenfield development from I-95 north to the Columbia pipeline. The segment of the alternative route that follows I-95 also is significantly encroached upon by adjacent residential and commercial development, and thus would increase potential impacts and construction-related constraints.

The majority of this route would require close coordination with the MDOT along the I-95 corridor, and would require additional construction safety requirements to construct due to passing traffic. This coordination and the addition of bang trucks would potentially lead to additional time to construct due to restricted hours of construction imposed by the MDOT (need to avoid rush hour periods), and possibility of delays if approved vehicles were not available. This would lead to additional time, cost and related potential impacts. Once leaving the I-95 corridor, much of the proposed route is open agricultural construction. This area would require seasonal restrictions as well as additional requirements for topsoil segregation and follow up mitigation efforts. Depending on sequencing of construction and actual timing of when this area is reached, this potentially could cause a temporary delay and additional associated impacts due to the increased CROW for topsoil segregation plan and follow up restoration and mitigation.

10.6.4 Route Variations

Minor variations on the proposed route were identified in response to issues raised by the public, engineering and environmental constraints identified during field surveys, and other issues of concerns. Figures 10.6.4-1 through 10.6.4-14 present twenty five (25) variations that were identified. Each potential variation on the proposed route was evaluated according to key environmental and engineering parameters to arrive at a preferred route through the area of concern. The purpose for developing route variations was to further refine the primary route in areas of potential significant impacts, including heavily congested and environmentally sensitive areas. Areas for focused route variations were identified during the course of public meetings, by landowners, during AES field surveys, and through agency input. Route variations were incorporated at various stages of the Project routing and field survey.

The process of public meetings, landowner contacts, and agency input has resulted in numerous additional changes from the initial conceptual route. These variations were incorporated at various stages of the project and survey efforts to improve routing and potential for public acceptance of the overall route.

A summary of the route variations along the route is presented in Table 10.6.4-1, Summary of Variations, including an environmental analysis of each variation.

Route Variation 1

Route variation number 1, from MP 3.75 to MP 4.75 as shown on Figure 10.6.4-1, was developed as an alternative to 1 mile of the original pipeline route, and follows Bunny Lane. The original route was located within a congested area located between I-695 and railroad tracks that also passed through a forested wetland. AES is evaluating Route Variation 1 to reduce construction-related constraints and to minimize impacts to wetlands.

Route Variation 2

Route variation number 2, from MP 4.75 to MP 5.35 as shown on Figure 10.6.4-1, was developed as an alternative to 0.75 mile of the original pipeline route, and is located between I-695 and commercial development. The original route was located paralleling I-695 that also passed through a forested wetland. AES is evaluating Route Variation 2 to reduce construction-related constraints and to minimize impacts to wetlands.

Route Variation 2a

Route variation number 2a, from MP 5.60 to MP 6.00 as shown on Figure 10.6.4-1, was developed as an alternative to 0.40 mile of the original pipeline route, and is located at the I-695 interchange. AES is evaluating Route Variation 2a to reduce construction-related constraints.

Route Variation 3

Route variation number 3, from MP 9.05 to MP 11.00 as shown on Figure 10.6.4-2, was developed as an alternative to 1.95 mile of the original pipeline route, and is located paralleling the south bound lane of I-695. AES is evaluating Route Variation 3 to reduce constructability issues through a congested corridor.

Route Variation 4

Route variation number 4, from MP 11.00 to MP 19.00 as shown on Figure 10.6.4-3, was developed as an alternative to 8 mile of the original pipeline route, and is located paralleling the north bound lane of I-695 and then I-95. AES is evaluating Route Variation 4 to reduce constructability issues through a congested corridor.

Route Variation 5

Route variation number 5, from MP 14.60 to MP 14.80 as shown on Figure 10.6.4-4, was developed as an alternative to 0.20 mile of the original pipeline route, and is located on the southern side of the existing overhead electrical transmission line. AES is evaluating Route Variation 5 to minimize impacts to wetlands.

Route Variation 6

Route variation number 6, from MP 15.25 to MP 15.50 as shown on Figure 10.6.4-4, was developed as an alternative to 0.25 mile of the original pipeline route, and is located on the northern side of the existing overhead electrical transmission line. AES is evaluating Route Variation 6 to minimize impacts to wetlands.

Route Variation 7

Route variation number 7, from MP 18.00 to MP 18.10 as shown on Figure 10.6.4-5, was developed as an alternative to 0.10 mile of the original pipeline route, and in located on the southern side of the existing overhead electrical transmission line. AES is evaluating Route Variation 7 to avoid residential structures.

Route Variation 8

Route variation number 8, from MP 18.75 to MP 19.00 as shown on Figure 10.6.4-5, was developed as an alternative to 0.25 mile of the original pipeline route, and is located to the west of the proposed route. AES is evaluating Route Variation 8 to avoid constructability issues through a congested corridor.

Route Variation 8a

Route variation number 8a, from MP 33.80 to MP 34.10 as shown on Figure 10.6.4-6, was developed as an alternative to 0.30 mile of the original pipeline route, and paralleling the north side of the existing pipeline easement. AES is evaluating Route Variation 8a to reduce construction-related constraints.

Route Variation 9

Route variation number 9, from MP 35.50 to MP 35.75 as shown on Figure 10.6.4-7, was developed as an alternative to 0.25 mile of the original pipeline route, and paralleling the north side of the existing pipeline easement. AES is evaluating Route Variation 9 to avoid residential structures.

Route Variation 10

Route variation number 10, from MP 36.20 to MP 37.70 as shown on Figure 10.6.4-7, was developed due to public comment as an alternative to 1.5 mile of the original pipeline route. At MP 36.20, the route variation turns north towards Mine Branch Road and the heads northeast on the north side of Mine Branch Road past Ady Road. Continuing northeast, the route variation is located south of Dublin Road to MP where the route variation rejoins the proposed route. AES is evaluating Route Variation 10 to avoid residential structures, steep terrain waterbodies and wetlands.

Route Variation 11

Route variation number 11, from MP 36.50 to MP 39.00 as shown on Figure 10.6.4-8, was developed as an alternative to 2.50 mile of the original pipeline route, and paralleling the south side of the existing pipeline easement. AES is evaluating Route Variation 11 to avoid residential structures. This variation is not preferred due to traversing Scarboro landfill.

Route Variation 12

Route variation number 12, from MP 39.50 to MP 40.00 as shown on Figure 10.6.4-8, was developed as an alternative to 0.50 mile of the original pipeline route, and paralleling the north side of the existing pipeline easement. AES is evaluating Route Variation 12 to avoid residential structures. This variation is not preferred due to required greenfield development.

Route Variation 13

Route variation number 13, from MP 51.75 to MP 53.15 as shown on Figure 10.6.4-9, was developed as an alternative to 1.35 mile of the original pipeline route, and is located to the northwest of the existing pipeline easement. Based on public comment, AES is evaluating Route Variation 13 to avoid residential structures and congested areas.

Route Variation 14

Route variation number 14, from MP 65.00 to MP 65.25 as shown on Figure 10.6.4-10, was developed as an alternative to 0.25 mile of the original pipeline route, and continue along the existing pipeline easement. AES is evaluating Route Variation 14 to avoid residential structures.

Route Variation 15

Route variation number 15, from MP 75.25 to MP 76.50 as shown on Figure 10.6.4-11, was developed as an alternative to 1.25 mile of the original pipeline route, and is located along the existing pipeline easement. AES is evaluating Route Variation 15 to avoid residential structures.

Route Variation 16

Route variation number 16, from MP 75.25 to MP 76.50 as shown on Figure 10.6.4-11, was developed as an alternative to 1.25 mile of the original pipeline route, and is located to the northwest of the existing pipeline easement. AES is evaluating Route Variation 16 to avoid residential structures.

Route Variation 17

Route variation number 17, from MP 77.50 to MP 78.50 as shown on Figure 10.6.4-12, was developed as an alternative to 1 mile of the original pipeline route, and is located to the east of the proposed route along the existing pipeline easement. AES is evaluating Route Variation 17 to avoid residential structures.

Route Variation 18

Route variation number 18, from MP 79.25 to MP 80.25 as shown on Figure 10.6.4-12, was developed as an alternative to 1 mile of the original pipeline route, and is located to the southeast of the proposed route. AES is evaluating Route Variation 18 to avoid residential structures, however, based on public comment the proposed route is preferred.

Route Variation 19

Route variation number 19, from MP 80.90 to MP 81.50 as shown on Figure 10.6.4-13, was developed as an alternative to 0.60 mile of the original pipeline route, and is located to the west of the proposed route. AES is evaluating Route Variation 19 to avoid residential structures.

Route Variation 20

Route variation number 20, from MP 81.50 to MP 82.25 as shown on Figure 10.6.4-13, was developed as an alternative to 0.75 mile of the original pipeline route, and is located to the east of the proposed route. AES is evaluating Route Variation 20 to avoid residential structures.

Route Variation 20a

Route variation number 20a, from MP 85.10 to MP 85.85 as shown on Figure 10.6.4-14, was developed as an alternative to 0.75 mile of the original pipeline route, and is located to the east of the proposed route. AES is evaluating Route Variation 20a to reduce construction-related constraints.

Route Variation 21

Route variation number 21, from MP 85.00 to MP 86.75 as shown on Figure 10.6.4-14, was developed as an alternative to 1.75 miles of the original pipeline route, and is located to the east of the proposed route along Park Road and Pottstown Pike. This route variation was developed in response to a comment made by the Township of Upper Uwchlan at a public hearing on June 6, 2006. Since that public hearing, AES met with the Township on June 20, 2006, and has been working with the Township to develop a viable route variation as represented on Figure 10.6.4-13. AES is evaluating Route Variation 21 to avoid residential structures.

Route Variation 22

Route variation number 22, from MP 87.00 to MP 87.50 as shown on Figure 10.6.4-14, was developed as an alternative to 0.50 mile of the original pipeline route, and is located to the west of the proposed route. Based on public comment, AES is evaluating Route Variation 22 to avoid residential and commercial development.

10.7 Summary

The North American natural gas industry is facing a critical period over the next ten to 15 years where increased supply availability will be essential. Given that the unsatisfied demand for energy supply available from natural gas is unacceptable, i.e., consumers demand natural gas due to the efficiencies and environmental benefits it offers, alternatives not meeting the purpose and need of the Project were not considered viable, including the no action alternative.

System alternatives for the proposed LNG Terminal were considered. These alternatives include the expansion of existing or approved LNG terminals, including Crown Landing LNG and Dominion Cove Point LNG. In addition, AES evaluated trans-continental pipeline projects such as the Rockies Express Pipeline, and the Mackenzie Gas Project. Given the forecasted decrease in production of natural gas in supply basins that serve the Mid-Atlantic Region, LNG is projected to supply not only incremental increases in natural gas demand, but also to replace the projected reduction in other supply components, *i.e.* natural gas imports from Canada and certain United States production basins. For this reason, neither the expansion of existing or proposed LNG terminal projects nor the proposed trans-continental pipeline projects would be an efficient system alternative to the Project. In addition, trans-continental pipeline projects, without accompanying construction of one or more LNG terminals, would not serve the Project purpose of accessing supplies of natural gas from world production centers. The commercial feasibility of serving the Mid-Atlantic Region from sources outside the Region (whether those sources are production basins in North America or LNG terminals) further limits the acceptability of such alternatives. Finally, the additional Project benefit of introducing new natural gas storage facilities into the area would not be realized.

AES utilized seven criteria to evaluate locations of the LNG Terminal, including alternatives for offshore and onshore options. Consideration of design features, including deepwater access, distance to residential areas so as to provide a wide margin of safety for the public in any worst-case event, and disruptions to maritime traffic, led to the conclusion that only projects sited along the Mid-Atlantic seaboard or within the Chesapeake Bay would be a feasible alternative to the proposed site at Sparrows Point. Once all offshore terminal locations were eliminated from further consideration, seven onshore alternative locations within the Chesapeake Bay were evaluated in detail. Four of the alternative sites were eliminated due to close proximity to residential areas. Two other alternatives were eliminated because obtaining site control within a reasonable and timely manner did not appear likely. Finally, one alternative was eliminated due to the need to route the associated natural gas pipeline through more densely populated areas than the preferred location at the proposed Terminal Site.

Four pipeline system alternatives to its proposed Pipeline were evaluated, none of which is considered to be a viable alternative. AES identified five alternative routes for the Pipeline. In accordance with conventional pipeline routing principles, collocation with existing utility corridors to the maximum extent possible was the primary routing strategy. The primary strategy was buffered by evaluation of a range of environmental, engineering, and socio-economic variables. An existing natural gas pipeline corridor controlled by Columbia, which traverses northeasterly across northeastern Maryland and southeastern Pennsylvania, was identified as the primary route corridor for the northern portion of the Pipeline. This portion of the proposed Pipeline Route would comprise approximately 65 percent of the total Pipeline length. The Columbia corridor offers the proper direction and shortest distance, thereby decreasing potential physical, natural, and human resource impacts. The proposed Pipeline Route and four route alternatives were evaluated south of the Susquehanna River in Maryland. Based on a combination of variables, a combination of route alternatives having the least overall environmental and socio-economic impact was selected for the southern portion of the route.

LNG terminal design alternatives, dredging methods and dredged material management alternatives were also evaluated in order to avoid or minimize environmental impacts, and effect on waterway users based on public input received, and consistent with local available options such as access to land. Based on the analyses presented above, AES believes that the identified preferred alternatives meet the goals of providing the alternatives that avoid or minimize potential environmental impacts.

10.8 References

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TABLES

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Resource Report 10- Alternatives
Table 10.5.1.3-2
Comparison of Proposed LNG Terminal Location and Seven Alternative Locations for the AES Sparrows Point Project

Citing Criteria	Unit	Sparrows Point Location	Calvert Cliffs Alternative	Cove Point Alternative	Greenbury Alternative	Fishing Point Alternative	Swan Creek Alternative	Kent Island Alternative	Mittal Steel Alternative
Land Use									
Distance from Residential Concentrations	(mi)	1.1	< 1.0	0.3	< 0.5	1.2	< 1.0	< 0.5	1.9
Estiamted Popluation within 1mile		0	708	1730	1327	0	211	249	0
Existing Land Use	type	industrial	Nuclear Power Plant	LNG Terminal	undeveloped / agricultural	industrial	agricultural	industrial	industrial
Zoning	type	industrial	industrial	industrial	residential	industrial	industrial	industrial	industrial
Design Factors									
Size of Site (on land)	(ac)	45.0	64.3	31.0	34.3	46.7	46.4	40.0	50.0
Ability of Site to accommodate LNG terminal facilities based on AES siting Criteria	yes/no	yes	no	no	no	no	no	no	yes
Approximate Distance from Main Shipping Channel	ft.	6000	18200	13000	21000	1000	8000	29000	2500
Length of send out pipeline required (approx.)	(mi)	87.7	147.7	151.2	107.5	94.4	91.3	89.1	88.5
Technically and Economically Feasible	yes/no	yes	no	no	no	yes	no	no	yes
Adequate Air Draft under Bridge Crossings	yes/no	yes	yes	yes	yes	yes	yes	yes	yes
Located within Natural Gas Markets intended to serve	yes/no	yes	no	no	no	yes	yes	yes	yes
Mimimize Disruption of Channel Traffic	yes/no	yes	yes	yes	no	no	yes	yes	yes
Satisfy All Safety and Security Standards	yes/no	yes	no	no	no	yes	yes	no	yes
Site Acquisition Feasible and Timely	yes/no	yes	no	no	no	yes	no	yes	no
Environmental Impact									
Dredge Quantities Required	(million cubic yard)	3.8*	1.6	1.1	1.7	15.4	11.7	10.9	1.8
Wetland Impacts	(ac)	0.0	0.0	6.2	0.0	0.0	6.3	0.0	0.0
Threatened & Endangered Species	N/A	none	none	Impact to 0.12 acres of Speceis of DNR Concern Habitat	none	none	none	none	none

* volume accounts for 1.7 million cubit yard reduction associated with preferred pier design

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Table 10.5.2.4-1
Summary Comparison of Dredge Material Disposal Options
AES Sparrows Point LNG

				Relative Cost of Dredge/Transport/Disposition Method[5]			
Selected Dredge Material Disposal Method and Site[1]	**Available Capacity[2]**	**Regulatory Approvals and/or Agency(s) Necessary[3]**	**Consistency of Dredged Material Quality with Materials Normally Placed at Facility[4]**	**Dredging and Associated Water Transportation Cost**	**Processing Cost**	**Transportation and Disposal/Beneficial Use Cost**	**Total**
Offshore Disposal (e.g. open ocean facility, such as Dam Neck Ocean Disposal Site)	example: Dam Neck Ocean Disposal Site - 65 MCY[2]	COE, USEPA	Appears consistent, but may be limited to cleaner sediment from deeper in section to be dredged	0.5X	NA	NA	0.5X
Upland Disposal at mine reclamation site (Western MD or PA)	Bark Camp, PA capacity is 6 to 10 MCY; Other PA and MD mine sites requiring similar reclamation comprise in excess of 9500 acres with unknown capacity.	PADEP (for Bark Camp or other PA site); MDE, MDNR for similar site in MD Possibly USEPA	Consistent - material of similar to worse chemical quality from other ports currently is treated and placed at the Bark Camp reclamation site (example site).	0.75X	2.25X (at mine site)	3.5X to 4.5X	6.5X to 7.5X
Disposal at Existing Fill Site (e.g. Hart Miller Island or Poplar Island)	Available capacity at Hart Miller is reported as 18 MCY (2001 USCOE), however its capacity is subscribed through 2009 and it is projected for a 2010 closure date.	MDE	Consistent - Dredge material from the Port of Baltimore, including the shipping channel for the Sparrows Point area has been disposed at Hart-Miller.	X	NA	NA	X
Innovative reuse of amended dredged material at local site	Capacity limited only by storage room relative to market take-away.	MDE, MDNR, COE	Consistent - material of similar chemical quality has been similarly treated and reused in other states/agency jurisdictions.	0.75X	2.75X	X to 2X	4.5X to 5.5X
Innovative reuse of sand/gravel dredged material	Capacity limited only by storage room relative to market take-away.	MDE, MDNR, COE	Appears consistent, but may be limited to cleaner sediment from greater depths in section to be dredged	0.5X to 0.75X	0.5X to 1.5X	-X to 0.5X	0 to 2.75X

Notes:

1. See Resource Report 10 text for more complete description of each alternative option.
2. Capacity is based on reported information available from public sources. Where total capacity is currently unknown, relative capacity or factors that may affect capacity are provided. Estimate for Dam Neck is based on USCOE update in 1990 ("*Long Term Management Strategy for Dredged Material Disposal for the Naval Weapons Station*"). The July 2001 USCOE Baltimore Harbor and Channels Dredged Material Management Plan indicates the Dam Neck and three related ocean placement sites have "adequate capacity for the Virginia Channels" for which they were originally established "for the next 20 years."
3. Final list of agencies that may need to approve an action is dependant on specific site locations. List not intended to be exhaustive.
4. See Resource Report 2 *Water Use and Quality* for results of chemical analysis of sediments subject to dredging and comparison to other Port of Baltimore data.
5. Costs are presented on relative basis. Example value range for "X" may be approximately \$3 to \$4/CY for disposal at Hart-Miller Island (USCOE 2001 Dredge Material Management Plan estimates disposal cost at Hart Miller to be \$3.76/CY), and \$6 to \$10/CY for dredge and transport (again to Hart-Miller, as example). This total range of \$9 to \$14/CY is provided for example purposes only. Actual costs may be greater.

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Resource Report 10- Alternatives

Table 10.6.2-1

Environmental Comparison of Alternatives to the Proposed Primary Route

AES Sparrows Point Project

		Alternative 1		Alternative 2		Alternative 3		Alternative 4	
Environmental Factors	**Unit**	**PROPOSED ROUTE**	**Dundalk West Alternative**	**PROPOSED ROUTE**	**Western Corridor Alternative**	**PROPOSED ROUTE**	**SR 136 Alternative**	**PROPOSED ROUTE**	**US I-95 & Greenfield Alternative**
Total length	(mi)	7.0	6.0	22.6	21.0	21.3	22.1	23.8	25.3
Type of Right of right-of-way:									
New right-of-way	(mi)	0.0	0.0	0.0	0.0	0.0	13.5	0.0	15.6
Adjacent to existing pipeline right-of-way	(mi)	0.0	0.0		0.0	8.1	0.0	10.6	0.0
Adjacent to other existing rights-of-way (i.e., powerline, road, etc.)	(mi)	7.0	6.0	22.6	21.0	13.2	8.6	13.2	9.7
Steep terrain (> 20%)	(ft)	0.0	0.0	4925.5	3330.2	6715.0	898.4	6715.0	1421.6
Right-of-way requirements:									
Construction right-of-way	(ac)	22.1	15.9	69.4	70.5	64.4	65.4	72.0	71.0
Permanent right-of-way	(ac)	44.2	31.9	138.8	141.0	128.9	130.6	144.1	141.6
Wetlands:									
Forested wetlands	(ft)	205.5	11.9	1945.9	141.9	0.0	0.0	0.0	5.4
Scrub-shrub wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergent wetlands	(ft)	83.7	1247.5	6.2	0.0	0.0	0.0	0.0	0.0
Wetland complexes	(no.)	4.0	2.0	5.0	1.0	0.0	0.0	0.0	1.0
Waterbodies:									
Total waterbodies	(no.)	1.0	9.0	26.0	26.0	22.0	23.0	23.0	30.0
Total perennial waterbodies	(no.)	1.0	5.0	16.0	15.0	13.0	19.0	16.0	26.0
Major river crossings > (100 feet)	(no.)	0.0	3.0	0.0	1.0	1.0	2.0	2.0	4.0
Designated natural and scenic rivers	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Significant fisheries	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ponds/Lakes	(no.)	0.0	1.0	1.0	0.0	2.0	1.0	2.0	1.0
Federally listed endangered or threatened species:									
Habitat	(mi.)	0	0	0	0	0	0	0	0
Species	(no.)								
Cultural Resources:*									
National Historic Landmarks	(no.)	0	0	0	0	0	0	0	0
NRHP-listed properties	(no.)	0	0	0	0	0	0	0	0
NRHP-listed Historic Districts	(no.)	0	0	0	0	1	1	1	0
Unlisted /potenitally elgibale properties	(no.)	0	6	0	1	0	10	0	8
Potential Archaeological resource sites	(no.)	2	6	4	1	0	10	7	8

Notes:

[1] Area and number calculations are based upon a 100-foot-wide buffer area around each route, except for the waterbody features that are represented by the count crossed along the centerline of each route.

* Archaeological Resources only assessed, other than Districts

Resource Report 10- Alternatives
Table 10.6.2-1
Environmental Comparison of Alternatives to the Proposed Primary Route
AES Sparrows Point Project (cont.)

		Alternative 1		Alternative 2		Alternative 3		Alternative 4	
Environmental Factors	Unit	PROPOSED ROUTE	Dundalk West Alternative	PROPOSED ROUTE	Western Corridor Alternative	PROPOSED ROUTE	SR 136 Alternative	PROPOSED ROUTE	US I-95 & Greenfield Alternative
Land use:									
Forest	(mi.)	2.7	0.2	8.6	6.6	8.3	1.7	9.4	4.4
Agricultural	(mi.)	0.0	0.0	4.6	5.0	6.6	9.0	7.1	8.5
Open (e.g. non-forested, scrub-shrub, pasture)	(mi.)	1.4	2.2	3.5	6.0	2.0	0.6	2.1	0.6
Residential	(mi.)	0.1	0.0	1.7	2.7	3.5	2.7	4.2	1.5
Commercial/Industrial	(mi.)	2.3	1.3	3.2	1.5	0.1	7.2	0.1	9.1
Other (e.g. golf courses, recreation, parks)	(mi.)	0.5	1.2	0.1	0.2	0.1	0.0	0.1	0.0
Residences:									
Within 50 feet of construction work area	(no.)	0	3	7	10	6	24	7	12
Federal land:									
Bureau of Land Management	(mi.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other (i.e., wilderness areas, parks)	(mi.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
State land:									
State forest/parks	(no.)	0.0	0.0	3.0	2.0	2.0	2.0	2.0	2.0
Other (i.e., parks, open space, etc.)	(no.)	0.0	1.0	7.0	6.0	8.0	7.0	9.0	6.0
Trails:									
National Trails (i.e., Appalachian Trail, etc.)	(no.)	0	0	0	0	0	0	0	0
Other (i.e., snowmobile, hiking, biking, etc.)	(no.)	0	0	0	0	0	0	0	0
Recreation or other designated land use areas:									
Landfills, quarries, golf courses, etc.	(no.)	1.0	2.0	1.0	1.0	1.0	1.0	1.0	0.0
Paleontological resource sites	(no.)	0	0	0	0	0	0	0	0

Notes:
[1] Area and number calculations are based upon a 100-foot-wide buffer area around each route, except for the waterbody features that are represented by the count crossed along the centerline of each route.

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Resource Report 10- Alternatives

Table 10.6.4-1

Environmental Comparison of Variations

		Variation 1		Variation 2		Variation 2a		Variation 3		Variation 4	
Environmental Factors	**Unit**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**
Total length	(mi)	1.03	1.05	0.45	0.57	0.37	0.37	1.38	1.52	7.94	8.88
Type of Right of right-of-way:											
New right-of-way	(mi)	0.09	0.17	0.00	0.45	0.00	0.00	0.00	0.00	0.56	0.00
Adjacent to existing pipeline right-of-way	(mi)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjacent to other existing rights-of-way (i.e., powerline, road, etc.)	(mi)	0.94	0.88	0.45	0.12	0.39	0.37	1.38	1.52	7.38	8.88
Wetlands:											
Forested wetlands	(ft)	0.0	0.0	184.7	184.5	0.0	0.0	0.0	0.0	129.3	0.0
Scrub-shrub wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergent wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wetland complexes	(no.)	0.0	0.0	1.0	1.0	0.0	0.0	0.0	0.0	3.0	0.0
Waterbodies:											
Total waterbodies	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	13.0	10.0
Total perennial waterbodies	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	13.0	10.0
Major river crossings > (100 feet)	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0
Designated natural and scenic rivers	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Significant fisheries	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ponds/Lakes	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Land use:											
Forest	(mi.)	0.46	0.05	0.57	0.57	0.06	0.05	0.02	0.00	3.43	1.81
Agricultural	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.46	0.06	1.55	2.05
Open (e.g. non-forested, scrub-shrub, pasture)	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.02	0.22	0.59
Residential	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.48	1.00
Commercial/Industrial	(mi.)	0.57	1.01	0.00	0.00	0.17	0.27	0.59	1.44	0.01	3.45
Other (e.g. golf courses, recreation, parks)	(mi.)	0.00	0.00	0.00	0.00	0.17	0.05	0.00	0.00	0.25	0.00
Residences:											
Within 50 feet of construction work area	(no.)	0	0	0	1	5	0	1	0	42	10
Recreation or other designated land use areas:											
Landfills, quarries, golf courses, etc.	(no.)	0.0	0.0	0.0	0.0	1.0	1.0	0.0	0.0	1.0	0.0

Notes:

[1] Federal and State Lands, Trails, Cultural Resources and Endangered or Threatened Species were found to have no impact or the impacts were equal for the above variations.

Resource Report 10- Alternatives

Table 10.6.4-1

Environmental Comparison of Variations

		Variation 5		Variation 6		Variation 7		Variation 8		Variation8a	
Environmental Factors	**Unit**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**
Total length	(mi)	0.32	0.33	0.41	0.39	0.11	0.12	0.27	0.30	0.28	0.28
Type of Right of right-of-way:											
New right-of-way	(mi)	0.00	0.00	0.41	0.00	0.00	0.00	0.20	0.17	0.00	0.28
Adjacent to existing pipeline right-of-way	(mi)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.00
Adjacent to other existing rights-of-way (i.e., powerline, road, etc.)	(mi)	0.32	0.33	0.00	0.39	0.11	0.12	0.07	0.13	0.00	0.00
Wetlands:											
Forested wetlands	(ft)	0.0	72.3	570.1	1359.3	0.0	0.0	0.0	0.0	0.0	0.0
Scrub-shrub wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergent wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wetland complexes	(no.)	0.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Waterbodies:											
Total waterbodies	(no.)	1.0	1.0	2.0	5.0	0.0	0.0	0.0	0.0	3.0	3.0
Total perennial waterbodies	(no.)	1.0	1.0	2.0	5.0	0.0	0.0	0.0	0.0	3.0	3.0
Major river crossings > (100 feet)	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0
Designated natural and scenic rivers	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Significant fisheries	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ponds/Lakes	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Land use:											
Forest	(mi.)	0.25	0.25	0.41	0.39	0.00	0.00	0.00	0.00	0.19	0.14
Agricultural	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.31	0.09	0.14
Open (e.g. non-forested, scrub-shrub, pasture)	(mi.)	0.07	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential	(mi.)	0.00	0.00	0.00	0.00	0.11	0.12	0.00	0.00	0.00	0.00
Commercial/Industrial	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other (e.g. golf courses, recreation, parks)	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residences:											
Within 50 feet of construction work area	(no.)	0	0	0	0	2	0	0	0	2	0
Recreation or other designated land use areas:											
Landfills, quarries, golf courses, etc.	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

[1] Federal and State Lands, Trails, Cultural Resources and Endangere

Resource Report 10- Alternatives

Table 10.6.4-1

Environmental Comparison of Variations

		Variation 9		Variation 10		Variation 11		Variation 12		Variation 13	
Environmental Factors	**Unit**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**
Total length	(mi)	0.61	1.47	1.47	2.10	0.39	0.42	0.56	0.72	1.94	1.87
Type of Right of right-of-way:											
New right-of-way	(mi)	0.00	0.72	0.00	2.10	0.00	0.42	0.00	0.72	1.94	1.87
Adjacent to existing pipeline right-of-way	(mi)	0.61	0.00	1.47	0.00	0.39	0.00	0.56	0.00	0.00	0.00
Adjacent to other existing rights-of-way (i.e., powerline, road, etc.)	(mi)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wetlands:											
Forested wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scrub-shrub wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergent wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wetland complexes	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waterbodies:											
Total waterbodies	(no.)	3.0	7.0	2.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0
Total perennial waterbodies	(no.)	3.0	7.0	2.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0
Major river crossings > (100 feet)	(no.)	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Designated natural and scenic rivers	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Significant fisheries	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ponds/Lakes	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Land use:											
Forest	(mi.)	0.33	0.69	0.33	0.90	0.33	0.36	0.00	0.25	0.20	0.15
Agricultural	(mi.)	0.27	0.03	1.14	1.17	0.06	0.06	0.56	0.47	1.73	1.71
Open (e.g. non-forested, scrub-shrub, pasture)	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial/Industrial	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other (e.g. golf courses, recreation, parks)	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residences:											
Within 50 feet of construction work area	(no.)	2	0	4	0	2	1	3	0	2	3
Recreation or other designated land use areas:											
Landfills, quarries, golf courses, etc.	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

[1] Federal and State Lands, Trails, Cultural Resources and Endangere

Resource Report 10- Alternatives

Table 10.6.4-1

Environmental Comparison of Variations

		Variation 14		Variation 15		Variation 16		Variation 17		Variation 18	
Environmental Factors	**Unit**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**
Total length	(mi)	0.22	0.16	1.83	1.53	1.73	1.41	1.16	0.99	0.97	0.77
Type of Right of right-of-way:											
New right-of-way	(mi)	0.22	0.16	1.83	1.03	1.73	0.75	0.60	0.00	0.25	0.14
Adjacent to existing pipeline right-of-way	(mi)	0.00	0.00	0.00	0.50	0.00	0.66	0.18	0.99	0.73	0.43
Adjacent to other existing rights-of-way (i.e., powerline, road, etc.)	(mi)	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.00	0.00	0.20
Wetlands:											
Forested wetlands	(ft)	0.0	0.0	0.0	133.8	0.0	143.8	0.0	0.0	710.5	0.0
Scrub-shrub wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	407.9	0.0
Emergent wetlands	(ft)	0.0	0.0	0.0	29.1	0.0	6.4	0.0	0.0	0.0	0.0
Wetland complexes	(no.)	0.0	0.0	0.0	2.0	0.0	2.0	0.0	0.0	3.0	0.0
Waterbodies:											
Total waterbodies	(no.)	0.0	0.0	3.0	1.0	3.0	2.0	1.0	2.0	2.0	1.0
Total perennial waterbodies	(no.)	0.0	0.0	3.0	1.0	3.0	2.0	1.0	2.0	2.0	1.0
Major river crossings > (100 feet)	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Designated natural and scenic rivers	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Significant fisheries	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ponds/Lakes	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0
Land use:											
Forest	(mi.)	0.00	0.00	0.68	0.53	0.66	0.54	0.37	0.10	0.70	0.39
Agricultural	(mi.)	0.22	0.16	1.14	0.99	1.08	0.86	0.60	0.87	0.00	0.00
Open (e.g. non-forested, scrub-shrub, pasture)	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.36
Commercial/Industrial	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.00	0.20	0.06
Other (e.g. golf courses, recreation, parks)	(mi.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residences:											
Within 50 feet of construction work area	(no.)	2	2	2	2	2	15	24	20	10	18
Recreation or other designated land use areas:											
Landfills, quarries, golf courses, etc.	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

[1] Federal and State Lands, Trails, Cultural Resources and Endangere

Resource Report 10- Alternatives

Table 10.6.4-1

Environmental Comparison of Variations

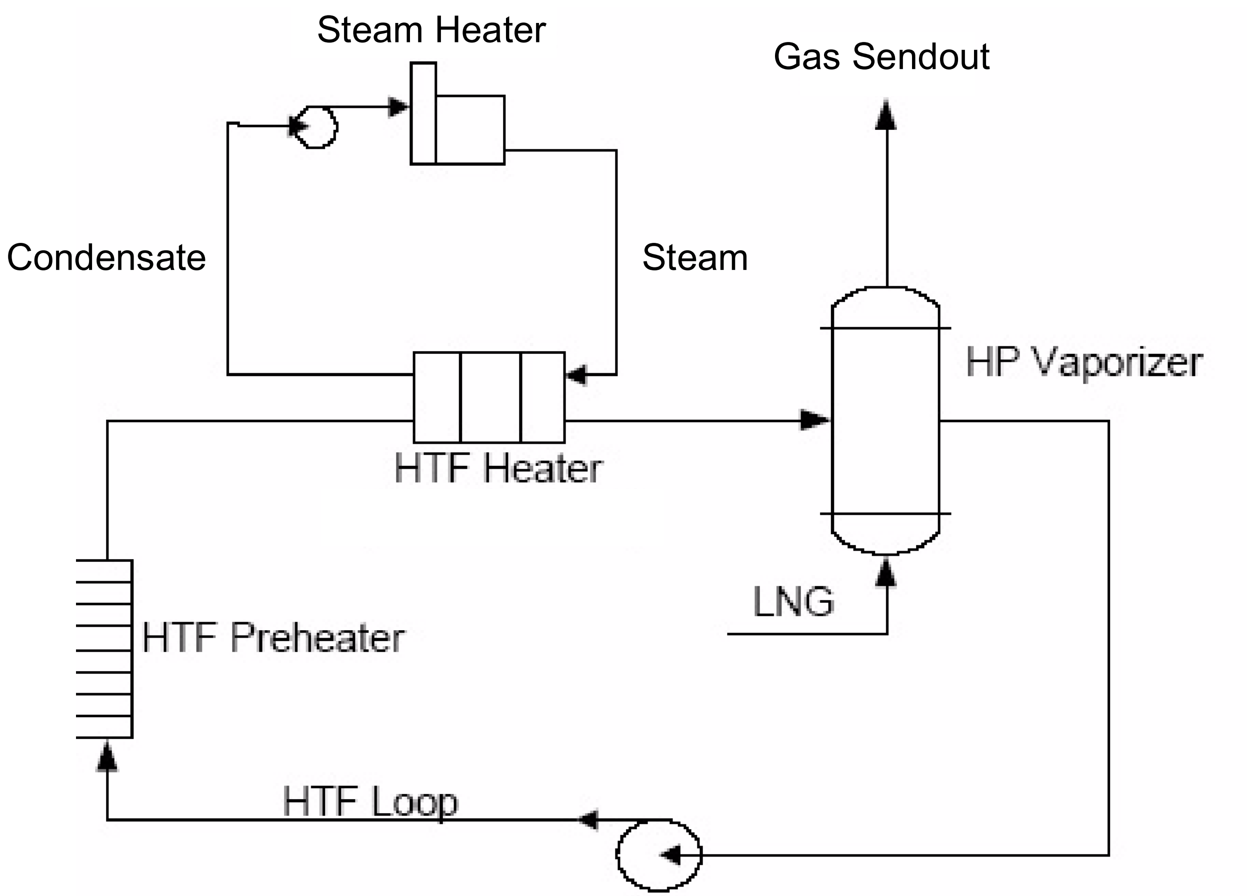
		Variation 19		Variation 20		Variation 20a		Variation 21		Variation 22	
Environmental Factors	**Unit**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**	**PROPOSED ROUTE**	**Variation**
Total length	(mi)	0.33	0.43	0.60	1.06	1.21	1.01	2.27	0.87	0.49	0.81
Type of Right of right-of-way:											
New right-of-way	(mi)	0.00	0.22	0.00	0.65	0.54	0.84	0.74	0.00	0.27	0.43
Adjacent to existing pipeline right-of-way	(mi)	0.33	0.21	0.60	0.41	0.30	0.00	0.70	0.00	0.00	0.00
Adjacent to other existing rights-of-way (i.e., powerline, road, etc.)	(mi)	0.00	0.00	0.00	0.00	0.37	0.17	0.83	0.90	0.22	0.38
Wetlands:											
Forested wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scrub-shrub wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergent wetlands	(ft)	0.0	0.0	0.0	0.0	0.0	0.0	59.0	0.0	0.0	0.0
Wetland complexes	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0
Waterbodies:											
Total waterbodies	(no.)	0.0	0.0	1.0	1.0	1.0	1.0	2.0	0.0	2.0	0.0
Total perennial waterbodies	(no.)	0.0	0.0	1.0	1.0	1.0	1.0	2.0	0.0	2.0	0.0
Major river crossings > (100 feet)	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Designated natural and scenic rivers	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Significant fisheries	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ponds/Lakes	(no.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Land use:											
Forest	(mi.)	0.30	0.35	0.27	0.74	0.08	0.25	0.16	0.00	0.02	0.00
Agricultural	(mi.)	0.00	0.00	0.00	0.00	0.15	0.00	0.22	0.29	0.07	0.03
Open (e.g. non-forested, scrub-shrub, pasture)	(mi.)	0.01	0.20	0.02	0.36	0.00	0.00	0.00	0.00	0.00	0.00
Residential	(mi.)	0.03	0.00	0.32	0.07	0.15	0.01	0.67	0.00	0.03	0.00
Commercial/Industrial	(mi.)	0.00	0.00	0.00	0.00	0.76	0.63	1.20	0.60	0.37	0.41
Other (e.g. golf courses, recreation, parks)	(mi.)	0.00	0.00	0.00	0.00	0.10	0.12	0.15	0.00	0.00	0.00
Residences:											
Within 50 feet of construction work area	(no.)	7	1	8	4	3	5	11	4	3	2
Recreation or other designated land use areas:											
Landfills, quarries, golf courses, etc.	(no.)	0.0	0.0	0.0	0.0	1.0	1.0	1.0	0.0	0.0	0.0

Notes:

[1] Federal and State Lands, Trails, Cultural Resources and Endangere

FIGURES

P:gis/projects/aes-100/rr10/apr/figure 10.4.2.1-3.mxd



SOURCE: DRAWING BY AES 2006.

PREPARED BY:
NEA, INC.

AES SPARROWS POINT LNG, LLC
BALTIMORE COUNTY, MD

PREFERRED OPTION REGASIFICATION METHOD – STEAM BOILERS

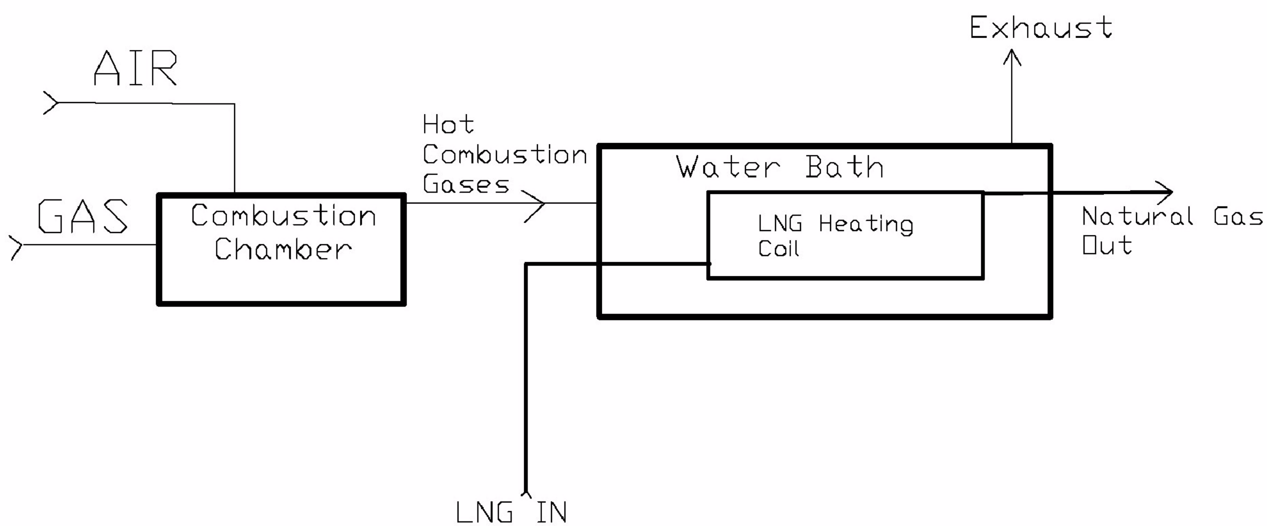
SCALE: NOT TO SCALE

10/10/06

FIGURE 10.5.2.2.-1

DRAFT

P:gis/projects/aes-100/rr10/apr/figure 10.4.2.1-3.mxd



SOURCE: DRAWING BY AES 2006.

Sparrows Point LNG

PREPARED BY:
NEA, INC.

AES SPARROWS POINT LNG, LLC
BALTIMORE COUNTY, MD

OPTION 1 (A & B) REGASIFICATION METHOD – SUBMERGED COMBUSTION VAPORIZOR

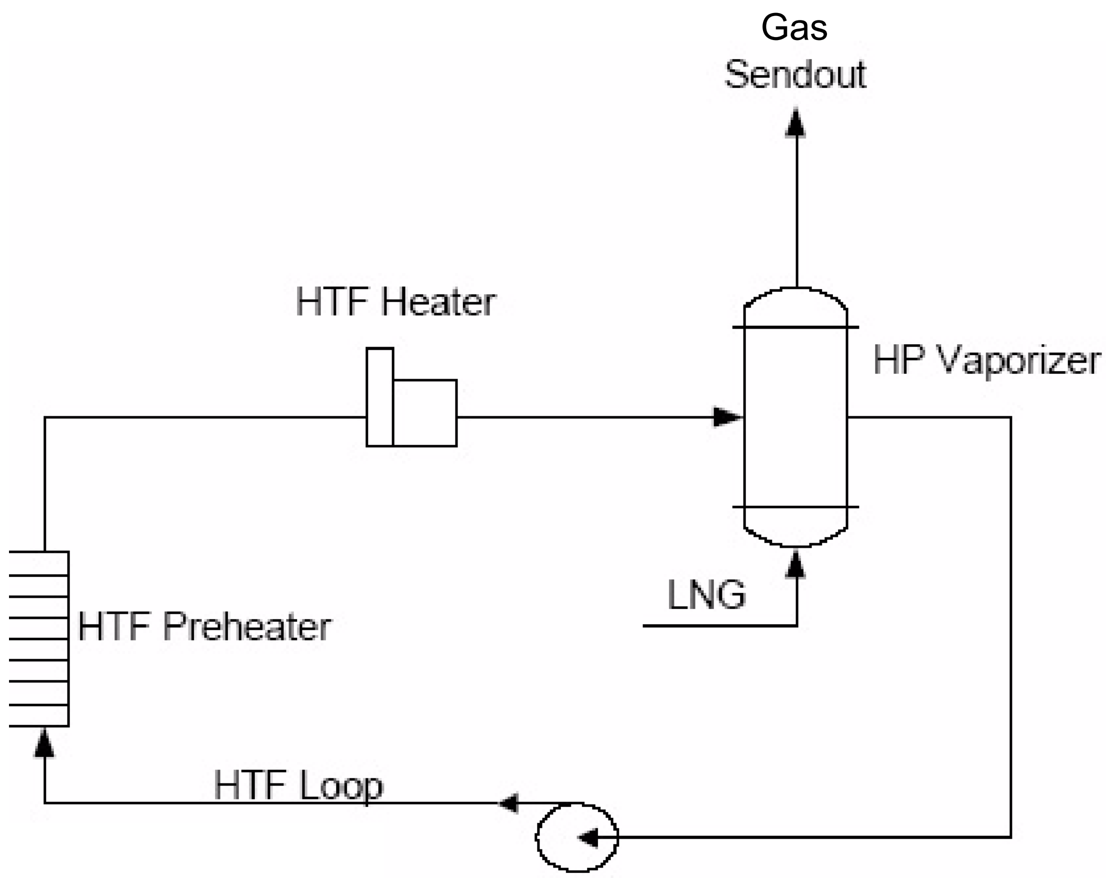
SCALE: NOT TO SCALE

10/10/06

FIGURE 10.5.2.2-2

DRAFT

P:gis/projects/aes-100/rr10/apr/figure 10.4.2.1-3.mxd



SOURCE: DRAWING BY AES 2006.

PREPARED BY:
NEA, INC.

AES SPARROWS POINT LNG, LLC
BALTIMORE COUNTY, MD

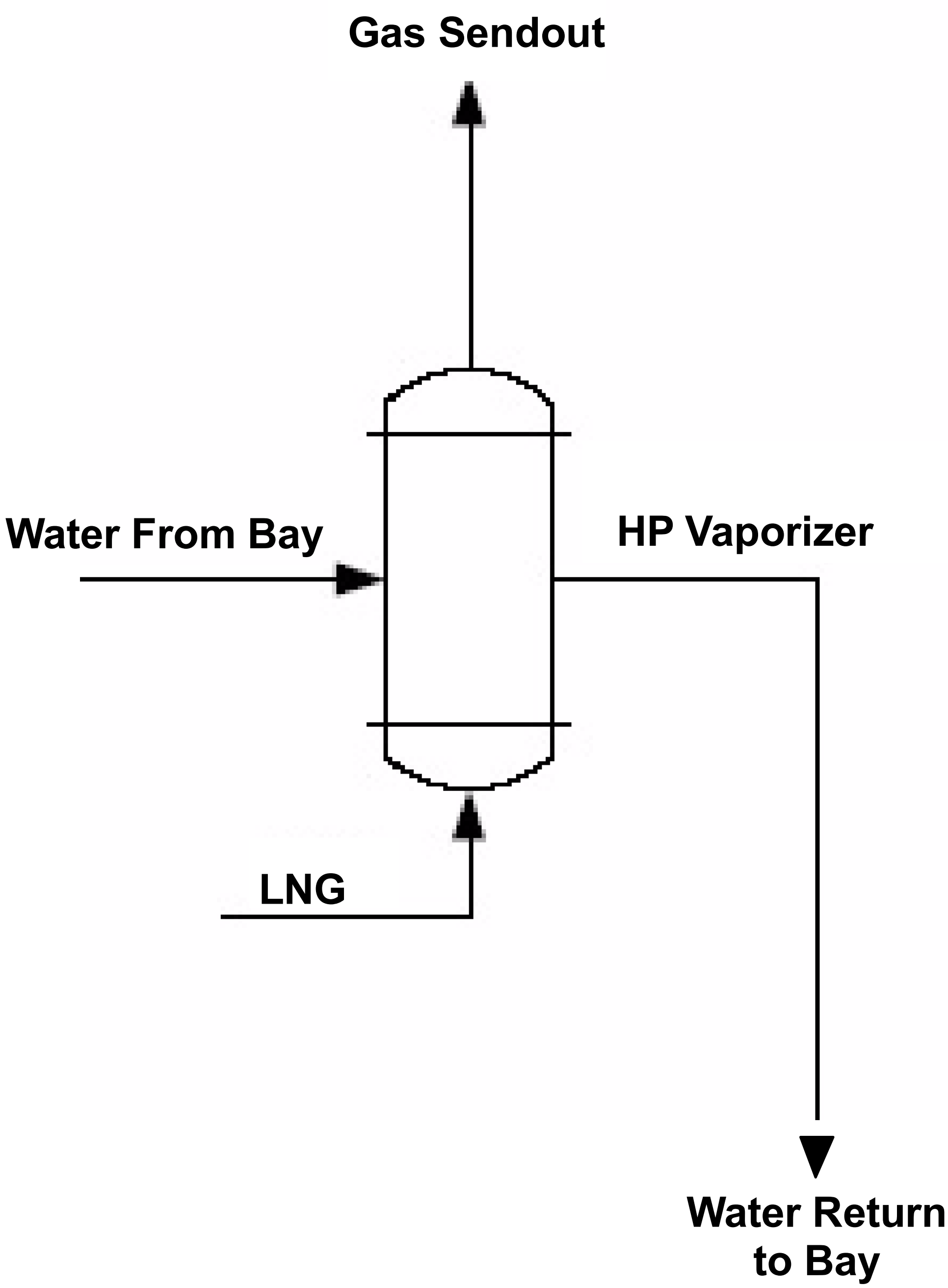
OPTION 2 (A & B) REGASIFICATION METHOD – GAS FIRED HEATERS

SCALE: NOT TO SCALE

10/10/06

FIGURE 10.5.2.2-3

DRAFT



SOURCE: DRAWING BY AES 2006.

Sparrows Point LNG

PREPARED BY:
NEA, INC.

AES SPARROWS POINT LNG, LLC
BALTIMORE COUNTY, MD

OPTION 3 REGASIFICATION METHOD – DIRECT SEAWATER EVAPORATION

SCALE: NOT TO SCALE

10/10/06

FIGURE 10.5.2.2-4

Additional Figures for Resource Report 10 classified as Non-Internet Public, and have been included in a separate volume.

APPENDIX A

CONCENTRIC ENERGY ADVISORS
DEMAND AND SUPPLY ANALYSIS OF THE MID-ATLANTIC NATURAL GAS MARKETS 2005-2030

DRAFT

DEMAND AND SUPPLY ANALYSIS OF THE MID-ATLANTIC NATURAL GAS MARKETS, 2005 - 2030

Prepared by:

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July 2006

TABLE OF CONTENTS

INDEX OF TABLES

INDEX OF TABLES (CONTINUED)

I. INTRODUCTION

A. Purpose of the Report

Mid-Atlantic Express, LLC has retained Concentric Energy Advisors, Inc. ("CEA") to evaluate the future demand for natural gas in the Mid-Atlantic Region (defined herein as New York, New Jersey, Pennsylvania, Maryland, Delaware, District of Columbia and Virginia), i.e., the primary markets that can receive natural gas either directly or through displacement from Mid-Atlantic Express, LLC and AES Sparrows Point LNG, LLC ("Sparrows Point"). Sparrows Point, which is an affiliate of Mid-Atlantic Express, LLC, will own and operate an LNG import terminal with an initial vaporization capacity of 1.5 Bcf/day.

The purpose of this report is to provide an independent assessment of the demand[1] for natural gas resulting from: (i) local distribution company ("LDC") growth; (ii) and electric generation requirements. The natural gas demand projections in the defined market (i.e., Mid-Atlantic Region) are forecasted over a twenty-five year period, from 2005 to 2030.

Specifically, this report is presented in three sections:

I. Introduction: In addition to the purpose of the report discussed above, this section describes the Mid-Atlantic and Sparrows Point projects;

II. Demand Projections: Provides an overview of U.S. natural gas demand and supply; natural gas demand projections for LDCs in the defined market, including a detailed explanation of the methodology utilized; and natural gas demand projections for electric generation in the defined market, including a detail explanation of the methodology utilized; and

III. Conclusions and Findings: Provides a summary of conclusions and findings based on the information presented in this report.

B. Sparrows Point and Mid-Atlantic Express

Sparrows Point is an import, storage and regasification facility located at the Sparrows Point Industrial Complex in Baltimore, Maryland.[2] Sparrows Point LNG will have three 160,000 cubic

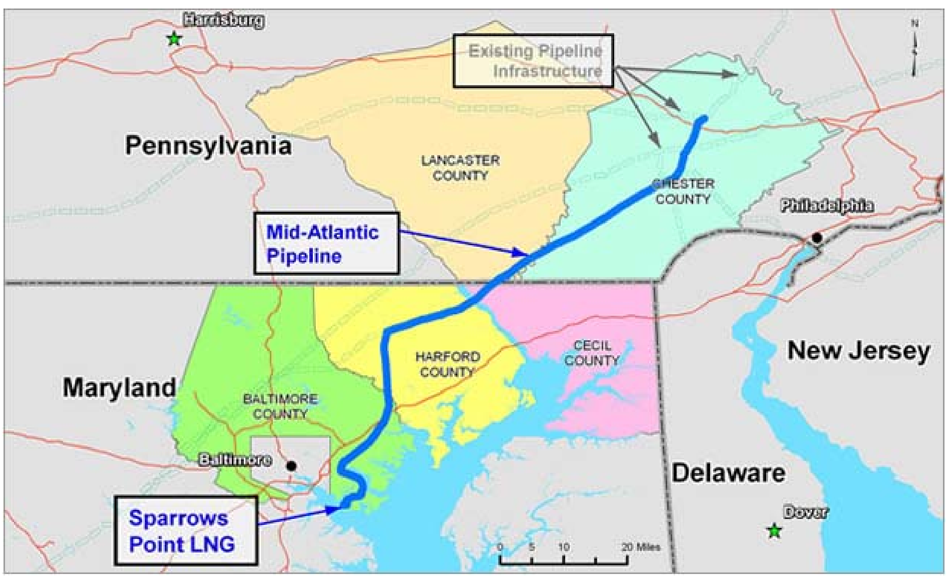
1 Although the focus of this report is the incremental natural gas demand forecast for the defined market, the issue of natural gas production declines in certain regions and the associated impact on the natural gas supply for the defined market is also reviewed.

2 AES Sparrows Point LNG, LLC and Mid-Atlantic Express LLC, Request to Initiate the Pre-Filing Process, submitted to the Federal Energy Regulatory Commission, Docket No. PF06-22-000, March 24, 2006, p. 1 of 13.

meter LNG storage tanks and a vaporization capacity of 1.5 Bcf/day, which could be expanded to 2.25 Bcf/day.[3]

The Sparrows Point facility will be connected to the U.S. natural gas pipeline grid via the Mid-Atlantic Express Pipeline. Specifically, as part of the Sparrows Point LNG project, Mid-Atlantic Express[4] will construct a new 87-mile natural gas pipeline (i.e., Mid-Atlantic Express Pipeline) that is expected to interconnect with Columbia Gas Transmission Corporation, Transcontinental Gas PipeLine Corporation, and Texas Eastern Transmission Corporation.[5] In addition to these pipeline interconnections, the Mid-Atlantic Express Pipeline is also expected to connect with Baltimore Gas and Electric.[6] Figure I-1 below, illustrates the approximate route AES will use to connect the Sparrows Point LNG facility to the U.S. natural gas pipeline grid near Eagle, Pennsylvania.

Figure I-1: Map of Proposed Mid-Atlantic Express Pipeline[7]



The Sparrows Point LNG facility and the Mid-Atlantic Express Pipeline have an expected in-service date of 2010.

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3 www.aessparrowspointlng.com.

4 Mid-Atlantic Express, LLC is a subsidiary of the AES Corporation.

5 AES Sparrows Point LNG, LLC and Mid-Atlantic Express, LLC, Request to Initiate the Pre-Filing Process, submitted to the Federal Energy Regulatory Commission, Docket No. PF06-22-000, March 24, 2006, p. 1 and 3 of 13.

6 Ibid, p. 2 of 13.

7 www.mid-atlanticexpress.com.

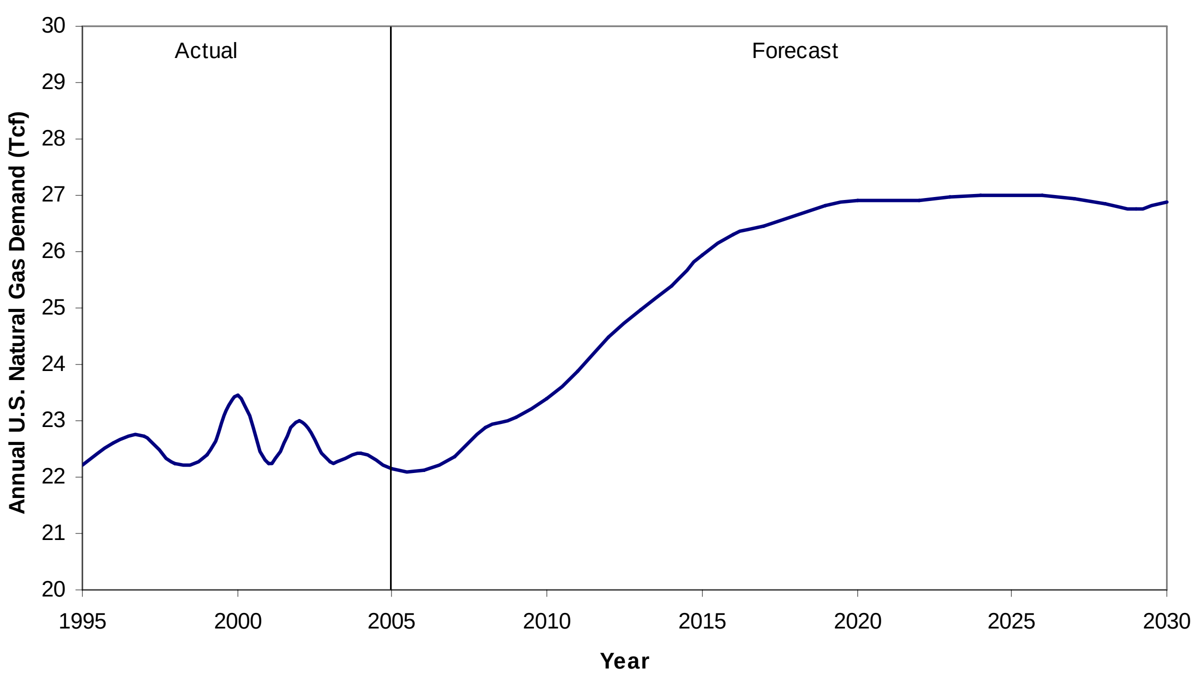
II. NATURAL GAS DEMAND

A. Natural Gas Demand/Supply Overview

Before discussing the methodology and results regarding future demand for natural gas in the defined market (i.e., the Mid-Atlantic Region), CEA will first provide a U.S. natural gas demand/supply overview.

U.S. natural gas consumption has remained between 22 Tcf and 23 Tcf over the last ten years (i.e., 1995 to 2005) as shown by Figure II-1 below. However, the Energy Information Administration ("EIA") is forecasting significant growth in U.S. natural gas demand for the ten year period from 2005 to 2015. Specifically, the EIA is projecting a 1.7% compounded annual growth rate for natural gas consumption from 2005 to 2015, which results in a U.S. natural gas demand increase from 22 Tcf in 2005 to 26 Tcf in 2015. For the period between 2016 to 2030, EIA has forecasted a modest growth in U.S. natural gas demand of 0.2% per year, which results in 27 Tcf of natural gas demand by 2030.

Figure II-1: U.S. Natural Gas Consumption, 1995 – 2030 (Tcf)[8]



[8] Energy Information Administration, "Short-Term Energy Outlook", April 2006, Table A6; Energy Information Administration, "The Annual Energy Outlook 2006", February 2006, Reference Case Table 2.

Although the projected U.S. consumption of 27 Tcf by 2030 will continue to be met with similar gas resources as the 2005 U.S. gas consumption (i.e., U.S. produced gas, gas imported from Canada, and LNG imports), the contribution of the individual supply components will change considerably.

Specifically, U.S. gas production is projected to increase from 18.2 Tcf in 2005 to 20.8 Tcf by 2030 and will continue to be the primary source of natural gas to meet U.S. consumption; however, U.S. gas production is projected to provide a smaller proportion of the overall U.S. natural gas demand. In other words, U.S. gas production met 82% of the overall U.S. gas requirement in 2005; however, by 2030, U.S. gas production is expected to provide 77% of the U.S. gas requirements.

In addition, certain U.S. natural gas supply regions will experience a decline in production over the forecast period. Specifically, as shown by Table II-1 below, the Gulf Coast and Gulf Off-Shore natural gas production, which has been a primary source of gas supply for the Mid-Atlantic U.S.,[9] will decline in both absolute and percentage terms over the forecast period.

Table II-1: Projected U.S. Natural Gas Production

	2005		2030	
U.S. Production	**(Tcf/year)**	**% of Total**	**(Tcf/year)**	**% of Total**
Gulf Coast	4.2	23%	3.5	17%
Gulf Off-Shore	4.1	22%	3.9	19%
Northeast	1.0	5%	1.5	7%
Rocky Mountain	4.1	23%	5.2	25%
Midcontinent	2.5	14%	2.1	10%
Southwest	1.6	9%	2.2	11%
Atlantic Off-Shore	0.0	0%	0.0	0%
West Coast	0.2	1%	0.1	1%
Pacific Off-Shore	0.1	0%	0.0	0%
Alaska	0.4	2%	2.1	10%
Total U.S. Production	18.2	100%	20.8	100%

9 Certain interstate pipelines that serve the Mid-Atlantic region receive natural gas supplies from the Gulf Coast. These pipelines include: Tennessee Gas Pipeline, Texas Eastern Transmission Company, Transcontinental Gas Pipeline Corporation, and Columbia Gas Transmission.

As illustrated in Table II-1 above, Gulf Coast and Gulf Off-Shore production comprised 45% of the U.S. natural gas production in 2005.[10] However, by 2030, these same two regions are forecasted to represent 36% of the total U.S. natural gas production.[11]

In other words, although total U.S. gas production is expected to increase over the forecast period, certain supply basins that have supplied the major U.S. long haul pipelines that serve the Mid-Atlantic region are forecasted to experience a supply reduction, which will increase the need for alternate supply sources for the Mid-Atlantic.

The second largest natural gas supply component to meet U.S. natural gas demand is natural gas imported from Canada. Unlike U.S. production, natural gas imports from Canada are projected to decline on both an absolute basis and as a percent of total U.S. demand requirements. Specifically, the total amount of gas imported from Canada in 2005 was approximately 3.2 Tcf, or 15% of total U.S. gas demand.[12] By 2030, the natural gas imported from Canada is projected to decline to 1.8 Tcf, or 7% of the total projected U.S. gas requirements.[13]

The final component of natural gas supplies utilized to meet U.S. demand, i.e., LNG, is projected to have the most significant change from 2005 to 2030. Specifically in 2005, 0.6 Tcf of the total U.S. natural gas demand, or 3%, was met by LNG imports.[14] By 2030, LNG imports are projected to increase to 4.4 Tcf, or approximately 16% of U.S. natural gas requirements.[15]

The forecasted decline in certain U.S. natural gas producing regions, as well as the forecasted reduction in Canadian natural gas available to meet U.S. demand, will impact the Mid-Atlantic region to a greater extent than the U.S. in general. As discussed above, natural gas from Canada currently supplies approximately 15% of the U.S. natural gas demand, and approximately 16% of the Mid-

10 U.S. Energy Information Administration, "Supplemental Tables to the Annual Energy Outlook 2006", February 2006, Tables 102 and 104.

11 Ibid, Tables 102 and 104.

12 U.S. Energy Information Administration, "March 2006 Monthly Energy Review", March 28, 2006, Table 4.3.

13 U.S. Energy Information Administration, The Annual Energy Outlook 2006, February 2006, p. 86.

14 U.S. Energy Information Administration, "March 2006 Monthly Energy Review", March 28, 2006, Table 4.3.

15 U.S. Energy Information Administration, "The Annual Energy Outlook 2006", February 2006, p. 86.

Atlantic natural gas demand.[16] In addition, certain U.S. gas producing regions that are forecasted to decline are primary supply basins for the interstate natural gas pipelines that serve the defined market.

Therefore, the combination of these two factors (i.e., the forecasted decline in certain U.S. producing basins and the projected decrease in Canadian gas available to meet U.S. demand) will likely create a supply in-fill opportunity for certain gas supply resources, such as LNG or Rocky Mountain sourced natural gas. For example, by 2010, the Gulf Coast, Gulf Off-shore and Northeast natural gas supply regions in aggregate are forecasted to decline by 4%, while the gas available from Canada is forecasted to decline by 19%. As a result, the natural gas supply components that serve the Mid-Atlantic region will likely experience changes. Specifically as shown in Table II-2 below, the U.S. production and Canadian supply forecasts will result in a supply in-fill volume of approximately 198,222 MMcf by 2010 in the Mid-Atlantic region.[17]

Table II-2: 2004 Mid-Atlantic Natural Gas Demand and Current and Forecasted Supply Components

Supply Region	2004 Supply Components (MMcf)	2010 Forecasted Supply Components (MMcf)
Gulf Coast, Gulf Off-Shore and Northeast	2,172,858	2,095,166
Imports from Canada	468,582	348,053
LNG Imports	326,260	326,260
Supply In-Fill	N/A	198,222
Total 2004 Demand	**2,967,700**	**2,967,700**

This supply in-fill opportunity for the forecast horizon is summarized in Table II-3.[18]

---

16 Specifically, in 2004, the Mid-Atlantic region consumed approximately 2,967,700 MMcf of which 16% was natural gas from Canada, 73% was gas produced in the U.S., and 11% was imported LNG. Please note that CEA has made the following estimates regarding 2004 LNG consumption in the defined market: (i) 100% of the LNG imported at Cove Point, Maryland was consumed in the defined market; (ii) 61% of the LNG imported at Elba Island was consumed in the defined market; and (iii) 33% of the LNG imported at Lake Charles was consumed in the defined market.

17 The 2010 forecasted supply components shown in Table II-2 do not include additional supply requirements associated with forecasted increases in demand.

18 For illustrative purposes, it was assumed that all of the U.S. produced gas that supplies the Mid-Atlantic region is sourced from the Gulf Coast, Gulf Off-Shore, and the Northeast natural gas producing regions.

Table II-3: Total Mid-Atlantic Supply In-Fill Requirements

(MMcf/year from 2004 Base Year)	**2010**	**2015***	**2020***	**2025**	**2030**
Gulf and Northeast Production Decline	77,692	(95,262)	(19,014)	84,043	166,353
Canadian Imports Decline	120,529	148,687	241,679	227,403	209,883
Total Supply In-Fill (MMcf/year)	198,222	53,425	222,664	311,445	376,235
Total Supply In-Fill (MMcf/day)	**543**	**146**	**610**	**853**	**1,031**

* Please note that the negative numbers reflect an increase in Gulf Off-Shore production as forecasted by EIA.

As illustrated by Table II-3, the supply in-fill opportunity in the Mid-Atlantic region is projected to be approximately 543 MMcf/day in 2010 and 1,031 MMcf/day by 2030.

B. LDC Design Day Demand Projection

CEA evaluated natural gas demand for both the LDC segment (i.e., residential, commercial and industrial demand) and the power generation segment. For the LDC segment, CEA utilized a 'bottom-up' modeling methodology by compiling and analyzing the most recent data available for each LDC in the defined market.

This methodology involved compiling design day demand forecast data available for each LDC in the defined market, reviewing those projections for accuracy and reasonableness, adjusting them as necessary, and then aggregating the forecasts into a state or regional projection. It is CEA's belief that the natural gas demand data filed by the individual LDCs are generally the most accurate and representative forecast of short-term sustainable natural gas demand growth.[19] In those instances when LDC forecast data was not available, CEA utilized LDC-specific data from financial reports or other publicly-available data;[20] however, the underlying methodology for projecting future demand was similar, regardless of data source.

19 Since most of the LDC-specific forecasts are approximately five years in length, CEA utilized the LDC-specified growth rate as a short-term growth rate covering that five-year period. Given the longer forecast horizon of this report, i.e., 25 years, the LDC-specified growth rate, while reflective of the LDC's short-term strategy, may not represent long-term sustainable growth. Therefore, CEA has modified certain LDC growth rates to be more reflective of LDC growth that is sustainable over the long-term.

20 For example, CEA utilized certain data from the U.S. Energy Information Administration.

1. New York

For the New York market, eleven LDCs were evaluated: Consolidated Edison Company of New York ("ConEd"), KeySpan Energy Delivery Long Island ("KeySpan-LI"), KeySpan Energy Delivery New York ("KeySpan-NY"), Orange & Rockland Utilities Inc. ("O&R"), Central Hudson Gas & Electric Corporation ("Central Hudson"), Niagara Mohawk ("NIMO"), New York State Electric and Gas ("NYSEG"), National Fuel Gas ("National Fuel"), Rochester Gas and Electric ("RG&E"), Corning Natural Gas Company ("Corning"), and St. Lawrence Gas ("St. Lawrence"). The primary sources for projecting design day demand in the New York market were the Securities and Exchange Commission ("SEC") Forms 10-K and the 2002 New York Gas Group Report to the New York State Planning Board.[21] Specifically, KeySpan-NY, KeySpan-LI and ConEd have historically reported their current estimate of design day demand in their Form 10-K. As such, CEA compiled the estimated design day demand for each of these LDCs for the past five winters to calculate a compound annual growth rate over this period. To project design day demand for the other LDCs in the New York market, CEA relied upon the information provided by these utilities in the 2002 New York Gas Group Report. While this data is not as up-to-date as the information for the larger LDCs, it is the most recent information available for projecting design day demand for these LDCs.

The following adjustments were made to the LDC projections:

- KeySpan's projected design day demand, when evaluated over the past five years (i.e., 2001 to 2005), resulted in a compound annual growth rate of 1.2%. However, the four year period from 2001 to 2004 resulted in a significantly greater compound average growth rate of approximately 2.0%. Therefore, to balance these different compound annual growth rates, CEA utilized a 1.5% annual growth rate for the KeySpan New York properties (i.e., KeySpan-NY and KeySpan-LI) based on our analysis of the data. The KeySpan SEC Form 10-K information provides an aggregated (i.e., KeySpan-NY and KeySpan-LI are not listed separately) design by demand projection. However, KeySpan projected in the 2002 New York Gas Group Report that Long Island would grow at a rate approximately 3.7 times faster than New York City. Due to the desire to utilize the most recent data available, it was assumed for this report that KeySpan-NY and KeySpan-LI, on a combined basis, would experience a compound annual design day demand growth rate of 1.5% and that the growth rate for Long Island would be approximately 3.7 times greater than the growth in New York City.

---

[21] It should be noted that the New York Gas Group merged with the New England Gas Association in 2003 to form the Northeast Gas Association ("NGA"). In 2004, NGA published an updated report regarding New York LDC demand; however, NGA's report does not provide as detailed information as the 2002 New York Gas Group Report, thus the information provided by NGA is not sufficient for purposes of this analysis.

- CEA believes that utilizing the combined growth rate of 1.5% for Long Island and New York City, as well as assuming that Long Island will grow at a rate substantially higher than New York City is reasonable due to various factors. First, KeySpan indicated in its 2004 Annual Report, as well as in various presentations to the financial community, that there is a significant opportunity for residential home heating and commercial growth in Long Island, while lower growth opportunity in its New York service territory due to higher gas penetration rates.[22]

  Therefore, for purposes of this analysis, it was assumed that KeySpan-NY and KeySpan-LI would grow at 0.7% and 2.6%, respectively, through the first ten years of the forecast.[23] For the remainder of the forecast period, it was assumed that KeySpan-NY would continue to grow at 0.7%, while KeySpan-LI would grow at the average compound annual growth rate of 0.9% or the same demand growth rate projected by O&R.

- ConEd projected design day demand that, when evaluated over the past five years, reflected a compound annual growth rate of 1.7%. However, a significant amount of design day growth occurred in the most recent two years, while the compound annual growth rate for the first three years was approximately 0.7%. Therefore, for purposes of this analysis, it was assumed that the short-term growth rate through 2010 for ConEd was 1.7% and for the long-term, i.e., the last 20 years of the forecast period, it was assumed that ConEd's compound annual design day demand growth would be 0.7%, or a rate more reflective of a sustainable, longer term rate of growth, particularly in a relatively saturated market.

- In the 2002 New York Gas Group Report, Central Hudson projected compound annual design day demand growth rate of 1.4%.[24] CEA believes that this level of demand growth may be possible in the short-term, but over the longer-term is not likely sustainable. Therefore, CEA utilized a design day demand growth rate of 1.4% for the first five years of the forecast period, and utilized a rate of 0.9% for the remaining twenty years, or the same demand growth rate projected by O&R, which is located in the same general geographic area.

- RG&E, St. Lawrence, and National Fuel: RG&E, St. Lawrence and National Fuel data provided in the 2002 New York Gas Group Report indicated no growth; however, given the long-term nature of this forecast, CEA utilized the NIMO growth estimate of 0.1% as the growth rate for these LDCs.

Table II-4 presents the projected design day demand based upon the methodology and adjustments described above.

22 See, e.g., 2004 KeySpan Energy Annual Report; KeySpan Energy Annual Presentation to the Financial Community, December 2004; "Executing on Our Strategy", presentation at 2005 CEO/Energy Power Conference, September 6, 2005.

23 Given KeySpan's specific programs targeting growth opportunities, CEA concluded that the 2.6% for KeySpan-LI was sustainable for the first ten years of the forecast period as opposed to five years as utilized for the other LDCs.

24 The 1.4% growth rate for Central Hudson was recently affirmed by Central Hudson in testimony filed in Case No. 05-E-0934 before the New York Public Service Commission.

Table II-4: Projected Design Day Demand – New York LDCs

(Figures in MMcf/day) Description	2005 2006	2009 2010	2014 2015	2019 2020	2024 2025	2029 2030	CAGR
New York							
Central Hudson	124	131	137	143	150	156	1.0%
Consolidated Edison	1,016	1,084	1,124	1,165	1,208	1,252	0.9%
Corning	58	59	61	62	63	65	0.4%
KeySpan-LI	932	1,031	1,172	1,225	1,280	1,338	1.5%
KeySpan-NY	1,182	1,215	1,258	1,302	1,348	1,395	0.7%
National Fuel	874	878	884	889	894	900	0.1%
Niagara Mohawk	1,041	1,046	1,053	1,059	1,065	1,072	0.1%
NYSEG	520	531	543	557	570	584	0.5%
O&R	222	230	241	252	263	275	0.9%
RG&E	511	513	516	519	522	526	0.1%
St. Lawrence	82	82	83	83	84	84	0.1%
Total Design Day Demand	**6,562**	**6,802**	**7,070**	**7,256**	**7,448**	**7,647**	**0.6%**
Incremental Design Day Demand		**240**	**508**	**693**	**886**	**1,085**	

As reflected in Table II-4, LDC design day demand in the New York market is projected to grow by approximately 508 MMcf/day over the next ten years and 1,085 MMcf/day over the next 25 years, or at a compound annual rate of 0.6%.

2. New Jersey

For the New Jersey market, CEA evaluated four LDCs: Public Service Electric and Gas ("PSE&G"), New Jersey Natural Gas ("NJN"), South Jersey Gas ("SJG"), and Elizabethtown Gas ("Elizabethtown"). To develop a design day proxy for the New Jersey LDCs, CEA relied on public information submitted by each LDC to the New Jersey Board of Public Utilities ("NJBPU"). Specifically, each utility submits a filing to the NJBPU titled "Annual Reports" which contains certain financial and operational data, including peak day sendout for that year.[25] For each New Jersey LDC, CEA reviewed six years of Annual Reports from 2000 to 2005, and utilized the highest observed peak day sendout as the proxy for design day demand as shown in Table II-5 below.[26]

[25] The New Jersey LDCs submit five-year forecasts of natural gas requirements and capacity entitlements to the New Jersey Board of Public Utilities every two years; however, these forecasts are submitted under confidentiality provisions and are not generally available to the public.

[26] SJG has historically reported its current estimate of design day demand in their Form 10-K. CEA utilized SJG's most recent design day estimate for winter 2005/06 as the proxy for design day demand as shown in Table II-6.

Table II-5: Summary of Peak Days – New Jersey LDCs

(Figures in MMcf/day) Description	2000	2001	2002	2003	2004	2005	Design Day Proxy
New Jersey							
PSE&G	2,401	2,180	2,181	2,401	2,504	2,473	2,504
South Jersey	349	340	422	428	423	361	428
New Jersey Natural	575	469	501	606	617	606	617
Elizabethtown Gas	446	362	399	422	422	446	446
New Jersey Total	**3,771**	**3,352**	**3,504**	**3,857**	**3,965**	**3,886**	**3,995**

Due to the lack of publicly-available demand forecasts (i.e., growth rates) for the New Jersey LDCs, CEA relied upon data from certain New York LDCs and a variety of publicly available information to project the New Jersey LDC design day demand:

- For the PSE&G design day demand growth rate, CEA utilized the growth rate for similarly-sized LDCs serving primary urban areas (i.e., KeySpan-NY and ConEd). Specifically, CEA utilized 0.8% (i.e., the simple average of the KeySpan-NY and ConEd design day demand growth rates) as PSE&G's design day demand growth rate throughout the forecast period.

- NJN reports a forecasted 2.3% annual demand growth rate in its 2005 Form 10-K, which is similar to the company's historic annual customer growth rate of 2.2% from 2001 through 2005.[27] NJN outlined significant growth potential through new customer additions and conversions in its suburban service territory which is in close proximity to New York City, Philadelphia, and the metropolitan areas of northern New Jersey. Therefore, for the short-term forecast period through 2009/2010, CEA utilized a rate of 1.5% or the same demand growth rate projected by KeySpan-LI, which is reflective of the growth rate associated with the LDCs that are projecting an aggressive short-term growth. For the remainder of the forecast period, CEA lowered the growth rate to 0.8% annually, reflecting the average growth rate for KeySpan-NY and ConEd. This demand growth rate reduction reasonably reflects longer-term market trends.

- Similar to NJN, SJG has experienced significant customer growth; specifically, customer growth has averaged 2.7% annually for the five-year period ending in 2004.[28] Strong new customer growth is expected to continue due to the company's service territory location between Philadelphia and Atlantic City. Therefore, similar to NJN, for the short-term forecast period through 2009/2010, CEA utilized a 1.5% annual design day demand growth rate, which is reflective of the growth rate for KeySpan-LI. Again similar to the assumption for NJN, the annual growth rate was lowered for the remainder of the forecast period to 0.8%, which is reflective of the average growth rate for KeySpan-NY and ConEd. This demand growth rate reduction reasonably reflects longer term market trends.

- Similar to the PSE&G analyses, CEA utilized a growth rate of 0.8% (i.e., the simple average of the KeySpan-NY and ConEd growth rates) for Elizabethtown as an estimate for design day demand growth.

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27 New Jersey Resources Presentation to New York Financial Community, December 6, 2005.

28 South Jersey Industries' 2004 Annual Report.

Table II-6 presents the projected design day demand for the New Jersey LDCs based upon the methodology described above.

Table II-6: Projected Design Day Demand – New Jersey LDCs

(Figures in MMcf/day) **Description**	**2005 2006**	**2009 2010**	**2014 2015**	**2019 2020**	**2024 2025**	**2029 2030**	**CAGR**
<u>New Jersey</u>							
PSE&G	2,504	2,583	2,686	2,793	2,904	3,020	0.8%
South Jersey Gas	511	544	570	592	616	641	0.9%
New Jersey Natural	617	655	686	714	742	772	0.9%
Elizabethtown Gas	446	460	479	498	518	538	0.8%
Total Design Day Demand	**4,078**	**4,243**	**4,421**	**4,597**	**4,780**	**4,971**	**0.8%**
Incremental Design Day Demand		**165**	**343**	**519**	**702**	**892**	

As reflected in Table II-6, incremental LDC design day demand in New Jersey is projected to grow by approximately 343 MMcf/day by 2015 and by 892 MMcf/day by 2030, or at a compound annual rate of 0.8% over the forecast period.

3. <u>Pennsylvania</u>

For the Pennsylvania market, CEA evaluated nine LDCs: PECO Gas ("PECO"), PG Energy, Philadelphia Gas Works ("PGW"), Columbia Gas of Pennsylvania ("Columbia-PA"), Equitable Gas Company ("Equitable Gas"), National Fuel Gas Distribution Corporation ("National Fuel"), Peoples Natural Gas Company ("Peoples"), PPL Gas Utilities ("PPL"), and UGI Utilities ("UGI"). To develop a design day proxy for the Pennsylvania LDCs, CEA relied on certain publicly available 1307(F) filings, Gas Annual Reports submitted by each LDC to the Pennsylvania Public Utilities Commission ("PA PUC"), and certain LDC annual financial reports. Design day demand estimates were provided by PECO, PG Energy and PGW. For each of the remaining Pennsylvania LDCs for which a design day demand estimate was not provided, CEA calculated a design day proxy. The following section discusses in detail the assumptions used for each LDCs' design day demand forecast.

- PECO provided a ten-year design day forecast through 2014/2015 in its 2005 1307(F) filing with the PA PUC. In its forecast, PECO projected an annual design day growth rate of 1.0%. CEA utilized this growth rate through the remainder of the forecast period.

- In its 2005 Annual Resource Planning Report[29], PG Energy provided a three-year design day forecast through the 2007/2008 which reflected a 0.6% compound annual growth rate. For 2009 through the remainder of the forecast period, CEA utilized the same growth rate of 0.6%.

- PGW provided five years of historic peak day sendout volumes in its 2005 1307(F) filing to the PA PUC[30]. CEA utilized the highest reported peak day sendout during the five-year period ending in 2003/2004 as a proxy for design day demand. Since design day demand growth rates were not available for PGW, CEA utilized the PG Energy growth rate of 0.6%.

- CEA reviewed four years of annual sales volumes as reported in Columbia-PA's Gas Annual Reports, which are filed with the PA PUC. CEA applied a 0.8%[31] assumed ratio of design day demand to the annual sales volumes and utilized the highest resulting peak day estimate over the four year period ending in 2005 as the design day demand proxy for Columbia-PA. Since design day demand growth rates were not available for Columbia-PA, CEA utilized the PG Energy growth rate of 0.6%.

- CEA utilized annual sales volumes as reported in Equitable Gas' 2005 Gas Annual Report.[32] Similar to Columbia-PA, CEA estimated a proxy design day demand for Equitable Gas by applying a 0.8% assumed ratio of design day demand to the 2005 total annual sales volume. Since design day demand growth rates were not available for Equitable Gas, CEA utilized the PG Energy growth rate of 0.6%.

- CEA utilized annual sales volumes as reported in National Fuel's 2005 Gas Annual Report filed with the PA PUC. Similar to Equitable Gas, CEA estimated a proxy design day demand for National Fuel by applying a 0.8% assumed ratio of design day demand to the 2005 total annual sales volume Since design day demand growth rates were not available for National Fuel, CEA utilized the PG Energy growth rate of 0.6%.

- CEA reviewed four years of annual sales volumes as reported in Peoples' Annual Reports, which are filed with the PA PUC. CEA applied a 0.8% assumed ratio of design day demand to the annual sales volumes and utilized the highest resulting peak day estimate over the four year period ending in 2005 as the design day demand proxy for Peoples. Since design day demand growth rates were not available for Peoples, CEA utilized the PG Energy growth rate of 0.6%.

- CEA reviewed annual sales volumes as reported in PPL's Annual Reports, which are filed with the PA PUC. CEA applied a 0.8% assumed ratio of design day demand to the annual sales volumes and utilized the highest resulting peak day estimate over the two year period

29 2005 Annual Resource Planning Report, Annual Gas Requirements; Form-IRP-Gas-1B Peak Day Requirements, June 1, 2005.

30 Philadelphia Gas Works, 2005 PA 1307(F) Filing, Item 53.64(c)

31 0.8% is consistent with peak day to annual sales ratios observed by PG Energy, PGW and LDCs in New York and New Jersey.

32 Specifically, in its 2005 Gas Annual Report filed with the PA PUC, Equitable Gas reports Pennsylvania direct sales volumes separate from Kentucky and West Virginia direct sales volumes. However, Equitable Gas does not identify transportation volumes by state. As such, CEA estimated the Pennsylvania transportation volume by allocating the total transportation volume by ratio of Pennsylvania direct sales volumes to Equitable Gas' total direct sales volumes.

ending in 2005 as the design day demand proxy for PPL. Since design day demand growth rates were not available for PPL, CEA utilized the PG Energy growth rate of 0.6%.

- CEA utilized annual firm sales volumes as reported in UGI's 2005 Annual Report[33] and applied a 0.8% assumed ratio of design day demand to the annual sales volumes and utilized the highest resulting peak day estimate over the six year period ending in 2005 as the design day demand proxy for UGI. CEA applied an annual growth rate of 1.0%, which is reflective of PECO's design day demand growth.

Table II-7 presents the projected design day demand for the Pennsylvania LDCs based upon the methodology described above.

Table II-7: Projected Design Day Demand – Pennsylvania LDCs

(Figures in MMcf/day) Description	2005 2006	2009 2010	2014 2015	2019 2020	2024 2025	2029 2030	CAGR
Pennsylvania							
Columbia Gas of Pennsylvania	698	715	737	760	783	808	0.6%
Equitable Gas	379	388	400	412	425	438	0.6%
National Fuel Gas	352	360	371	383	395	407	0.6%
PECO Gas	791	823	864	907	953	1,001	1.0%
Peoples Natural Gas	575	590	608	627	646	666	0.6%
PG Energy	358	367	379	390	402	415	0.6%
Philadelphia Gas Works	588	603	622	641	661	681	0.6%
PPL Gas Utilities	189	193	199	206	212	218	0.6%
UGI Utilities	469	488	513	538	565	594	1.0%
Total Design Day Demand	**4,399**	**4,527**	**4,693**	**4,864**	**5,043**	**5,229**	**0.7%**
Incremental Design Day Demand		**128**	**293**	**465**	**644**	**829**	

As reflected in Table II-7, LDC design day demand in Pennsylvania is projected to grow by approximately 293 MMcf/day over the next ten years and 829 MMcf/day over the next 25 years, or at a compound annual rate of 0.7%.

4. Mid-Atlantic–Other

Many of the other Mid-Atlantic LDCs have service territories that span more than one state. For this reason, CEA evaluated other Mid-Atlantic LDC demand on a combined regional basis and not separately for each state or district (i.e., District of Columbia, Maryland, Delaware, and Virginia). For the Mid-Atlantic–Other region, CEA evaluated the following ten LDCs: Baltimore Gas and

33 UGI Corporation, 2005 Annual Report, p. 62-63.

Electric ("BG&E"), Columbia Gas of Maryland ("Columbia-MD"), Chesapeake Utilities Corporation ("Chesapeake"), Delmarva Power and Light ("DP&L"), Columbia Gas of Virginia ("Columbia-VA"), Atmos Energy Corporation ("Atmos Energy"), Roanoke Gas Company ("Roanoke"), Southwestern Virginia Gas Company ("SVG"), Virginia Natural Gas ("VNG"), and Washington Gas Light ("WGL").

The first four LDCs listed above (i.e. BG&E, Columbia-MD, Chesapeake, and DP&L) serve customers in Maryland and Delaware. The primary sources for projecting design day demand for these four LDCs were from design day demand forecasts when available through IRPs or other regulatory filings and annual financial reports[34] as described below, specifically:

- BG&E provided a five-year peak day forecast through 2010 in its 2005 Annual Gas Capacity Plan.[35] In its demand forecast, BG&E projected an annual design day demand growth rate of 1.4%. CEA utilized a growth rate of 0.9% through the remainder of the forecast period, which is reflective of the average 25 year growth rate projected by the EIA for the combined Mid-Atlantic and South Atlantic census regions.[36]

- Similar to BG&E, DP&L provided a six-year peak day forecast through 2011 in its 2005 Gas Cost Rate Application[37] filing to the Delaware Public Service Commission. In this design day demand forecast, DP&L projected an annual design day demand growth rate of 2.4%. CEA utilized a growth rate of 0.9% through the remainder of the forecast period, which is reflective of the average 25 year growth rate projected by the EIA for the combined Mid-Atlantic and South Atlantic census regions.

- Chesapeake serves customers in both Maryland and Delaware. Chesapeake's Delaware Division reported its current estimate of design day demand in its 2005 Gas Sales Service Rate Application filing to the Delaware PSC[38]. A similar design day demand estimate for the Maryland Division was not available. As such, CEA also utilized annual sales volumes, which were reported by both Delaware and Maryland Divisions in their 2004 FERC Form 2A to develop a proxy for the Maryland Division's design day demand. Specifically, CEA calculated the percentage of design day demand to annual demand for the Delaware Division, applied this resulting percentage of 0.7% to the annual sales volume for the Maryland Division and utilized the highest resulting peak day estimate over the two year period ending in 2004 as the design day demand proxy for the Maryland Division. CEA

34 SEC Form 10-K and FERC Form 2A.

35 Baltimore Gas & Electric, Annual Gas Capacity Plan for Winters 2005/2006 through 2009/2010, Docket No. 8950, Phase II, Appendix B, October 19, 2005.

36 U.S. Energy Information Administration, "Supplemental Tables to The Annual Energy Outlook 2006", February 2006, Tables 2 and 5. The South Atlantic census region includes Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia. The Mid-Atlantic census region includes New Jersey, New York, and Pennsylvania.

37 Delmarva Power & Light, Gas Cost Rate ("GCR") Application Docket 05-312F, Schedule WTA-2, October 3, 2005

38 Chesapeake Utilities Corporation – Delaware Division, Gas Sales Service Rates ("GSR") Application, Docket 05-315F, Schedule A.1, November 1, 2005.

utilized a growth rate of 0.9% for both Delaware and Maryland Divisions, which is reflective of the average 25 year growth rate projected by the EIA for the combined Mid-Atlantic and South Atlantic census regions.

- A design day demand estimate for Columbia-MD was not available; therefore, similar to the methodology used for Chesapeake's Maryland Division, CEA applied a 0.7% assumed ratio of design day demand to the annual sales volumes reported by Columbia-MD in its 2005 Annual Report to the Maryland PSC and utilized the highest resulting peak day estimate over the two year period ending in 2005 as the design day demand proxy for Columbia-MD. CEA utilized an annual design day demand growth rate of 0.9% for Columbia-MD, which is reflective of the average 25 year growth rate projected by the EIA for the combined Mid-Atlantic and South Atlantic census regions.

Columbia-VA, Atmos Energy, Roanoke, SVG, and VNG serve customers solely in Virginia. WGL[39] serves customers in Virginia, in addition to customers in the District of Columbia and Maryland. The primary source for projecting design day demand for these LDCs serving the Virginia market was the Virginia State Corporation Commission ("SCC"), Division of Economics and Finance, 2004 Gas Supply Plan, which provides a five-year design day demand forecast through 2009 for each Virginia LDC.[40] CEA utilized the design day forecasts provided in the Virginia SCC Gas Supply Plan through 2009 and for 2010 through the remainder of the forecast period, applied a growth rate of 0.9%, which is reflective of the average 25 year growth rate projected by the EIA for the combined Mid-Atlantic and South Atlantic census regions. A more recent design day forecast was available for WGL, specifically:

- WGL provided a current design day forecast in its 2005 SEC Form 10-K for the winter 2005/06. CEA utilized this more recent design day forecast as the base design day proxy for WGL and applied an annual design day growth rate of 2.3% through 2009, which is reflective of the five-year growth rate projected for WGL in the Virginia SCC Gas Supply Plan. For 2010 through the remainder of the forecast period, CEA applied a growth rate of 0.9%, which is reflective of the average 25 year growth rate projected by the EIA for the combined Mid-Atlantic and South Atlantic census regions.

Table II-8 presents the projected LDC design day demand for the Mid-Atlantic–Other region based upon the methodology described above.

[39] Includes Washington Gas Light subsidiary, Shenandoah Gas Division.

[40] In addition to the 2004 Virginia Gas Supply Plan, WGL reported a more recent design day demand estimate in its 2005 SEC Form 10-K. CEA utilized this more recent design day estimate as a proxy for the winter 2005/2006 and applied the annual growth rate as reported by WGL in the 2004 Virginia Gas Supply Plan.

Table II-8: Projected Design Day Demand – Mid-Atlantic–Other Region LDCs

(Figures in MMcf/day) Description	2005 2006	2009 2010	2014 2015	2019 2020	2024 2025	2029 2030	CAGR
Mid-Atlantic-Other							
Baltimore Gas & Electric	913	964	1,010	1,058	1,108	1,160	1.0%
Chesapeake Utilities	51	53	56	59	61	64	0.9%
Columbia Gas of Maryland	48	50	52	55	57	60	0.9%
Delmarva Power & Light	180	198	209	219	230	241	1.2%
Columbia Gas of Virginia	358	384	402	421	441	462	1.1%
Atmos Energy	47	49	52	54	57	59	0.9%
Roanoke Gas Company	104	108	113	118	124	130	0.9%
Southwestern Virginia Gas	11	11	11	11	11	11	0.1%
Virginia Natural Gas	413	458	479	502	526	551	1.2%
Washington Gas Light	1,770	1,914	2,005	2,101	2,200	2,305	1.1%
Total Design Day Demand	**3,895**	**4,189**	**4,389**	**4,597**	**4,815**	**5,043**	**1.1%**
Incremental Design Day Demand		**293**	**494**	**702**	**920**	**1,148**	

As reflected in Table II-8, LDC design day demand in the Mid-Atlantic-Other region is projected to grow by approximately 494 MMcf/day over the next ten years and 1,148 MMcf/day over the next 25 years, or at a compound annual rate of 1.1%.

C. Gas-Fired Generation Demand Projection Methodology

To develop an estimate of natural gas demand for the electric generation segment, CEA had to first estimate the electricity demand in the defined market. Specifically, CEA developed an estimate of peak electric demand, including a reserve margin over the forecast horizon (i.e., 2006 to 2030) by utilizing data published by the respective regional power pool operator and reliability councils, i.e., New York Independent System Operator ("NYISO"), the PJM Interconnection ("PJM"),[41] and the North American Electric Reliability Council–Mid-Atlantic Area ("MAAC"). Once the peak electric demand forecast was developed, CEA compared the electric demand forecast to the available generation in the respective power pool market (i.e. NYISO or PJM), accounting for both projected additions and retirements, and calculated a surplus or deficiency.[42]

[41] PJM Interconnection is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. (www.pjm.com/about/overview.html)

[42] CEA did not forecast retirements of electric generation beyond what is currently projected through publicly-available sources.

If a deficiency was identified, the primary drivers that impact the amount of natural gas that may be required for the incremental capacity needs are: (i) whether the incremental capacity requirements are met by generation or transmission; (ii) if met by generation, whether the generation is natural gas-fired or utilizes an alternative fuel; and (iii) if met by generation, whether the generation is a peaking or a non-peaking resource. As such, if a deficiency was identified, CEA applied the following general assumptions to estimate gas requirements for power generation:

- Unless otherwise indicated, the identified deficiency was assumed to be met with generation not transmission;
- The percentage of the incremental generation to be met by natural gas-fired resources was specific to each power pool;
- The existing ratio of peaking to non-peaking generation resources are based on the existing generation resources in the NYISO, and that within each of the regions this ratio of peaking to non-peaking resources will remain constant throughout the forecast period;[43]
- All projected generation additions were assumed to have a heat rate of 7,196 btu/kWh, or a heat rate consistent with new combined cycle units;[44] and
- The incremental generation was assumed to operate for 24 hours on a design day.

1. New York

a. Electric Demand/Supply Balance

In order to determine the existing electric demand/supply balance in New York, CEA utilized certain demand and capacity information as reported by the NYISO in its latest Load and Capacity Report.[45] These figures were then adjusted to account for an additional 330 MW of transmission capacity into New York from Connecticut associated with the Cross Sound Cable. There are numerous generation facilities that have been announced; however, unless the facility was already under construction, it was not included in the projected future generation supply for purposes of

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43 Since generation data was not readily available for the power markets in New Jersey, Pennsylvania and the Mid-Atlantic–Other region, the generation resources in New York were utilized as a proxy for these other regions. Specifically, peaking resources (defined as those units with a capacity factor of less than 30% for 2004 and 2005) currently represent approximately 38% of the total generating resource base within the New York Control Area ("NYCA"). It was assumed that newly constructed peaking resources will not purchase long-term pipeline/LNG capacity, but rather would (i) utilize existing unutilized pipeline capacity in the summer to operate during peak periods (i.e., purchase delivered city-gate supplies when the gas is required); or (ii) use an alternate fuel (i.e., oil).

44 EIA in its *Assumptions to Annual Energy Outlook 2006* estimates the heat rate for a new conventional combined cycle and advanced combined cycle at 7,196 btu/kWh and 6,752 btu/kWh, respectively. (See EIA, "Assumptions to Annual Energy Outlook 2006", March 2006, p. 73).

45 New York Independent System Operator, 2006 Load and Capacity Data, Table III-2.

this report.[46] In addition, the existing generation supply was also adjusted to account for any known retirements as reported by the NYISO[47].

The NYISO currently utilizes a capacity reserve margin of 18% for determining capacity sufficiency in the New York Control Area ("NYCA"). Therefore for purposes of this analysis, the reserve margin for the NYCA is estimated to be 18% throughout the forecast period. In its demand forecast, the NYISO projected a summer peak load compound annual growth rate of 1.0% for the period 2006 through 2016. CEA assumed the summer peak load would continue to grow at this same rate through 2030. The analysis of the incremental need for capacity in NYCA is presented in Table II-9.

Table II-9: Projected Electric Generation Required in New York

(All Figures in MW, unless otherwise noted)	Summer						
Description	**2006**	**2010**	**2015**	**2020**	**2025**	**2030**	**CAGR**
NYCA							
Projected Summer Peak Load							
NYCA	33,833	35,729	37,080	38,824	40,779	42,833	1.0%
Plus: 18% Reserve Margin	6,090	6,431	6,674	6,988	7,340	7,710	
Total Peak Load and Reserve Margin	39,923	42,160	43,754	45,812	48,119	50,543	
Projected Summer Peak Capacity							
Installed Summer Peak Capacity	39,286	39,286	39,286	39,286	39,286	39,286	
Cumulative Planned Gas Additions	500	810	810	810	810	810	
Cumulative Planned Additions - Other	195	855	855	855	855	855	
Cumulative Scheduled/Planned Retirements	(165)	(1,675)	(1,675)	(1,675)	(1,675)	(1,675)	
Subtotal	39,816	39,277	39,277	39,277	39,277	39,277	
Add'l Cumulative Capacity Needed to Meet 18% Reserve Margin	**106**	**2,884**	**4,478**	**6,535**	**8,843**	**11,266**	

As shown in Table II-9, the summer peak load for the NYCA is currently 33,833 MW and is projected to grow to 42,833 MW by 2030 at a compound annual growth rate of 1.0%. The NYCA is projected to require approximately 2,884 MW of additional capacity by 2010, and 11,266 MW by 2030.

46 CEA assumed that there will be 810 MW of incremental gas-fired capacity built in the NYCA with the SCS Astoria Energy Phase I project (500 MW) on-line in 2006 and Caithness Bellport project (310 MW) on-line in 2008. CEA also assumed that 855 MW of additional capacity is built, including: the Ginna uprate (95 MW) effective in 2006, the Flat Rock Wind Power – Phase 2 project (100 MW) on-line in 2006, and the Neptune Transmission (660 MW) in-service in 2007.

47 CEA assumed 1,675 MW of retirements, including: Huntley 65/66 (165 MW) in 2006, Russell (231 MW) and Lovett 5 (176 MW) in 2007, and Lovett 3 & 4 (215 MW) and Poletti 1 (888 MW) in 2008.

b. Projected Natural Gas Requirement Associated With Incremental Peak Electric Demand

Utilizing the known gas-fired capacity additions, as well as the projected incremental capacity requirements reflected in the section above, CEA estimated the magnitude of the future natural gas demand in the NYCA. First, as shown in Table II-10, it was assumed for purposes of this analysis that all of the projected need for incremental capacity will be met by generation as opposed to transmission.

Table II-10: Projected Natural Gas Demand from Incremental Generation Capacity in New York

(All Figures in MW, unless otherwise noted)

Description	Summer 2006	2010	2015	2020	2025	2030
NYCA						
Additional Cumulative Capacity Needed	106	2,884	4,478	6,535	8,843	11,266
% of Add'l Capacity Needed Met by Gas-Fired Generation	100%	100%	100%	100%	100%	100%
Projected Add'l Capacity Needed Met by Gas-Fired Generation	106	2,884	4,478	6,535	8,843	11,266
Cumulative Planned Gas Additions	500	810	810	810	810	810
Total Gas-Fired Generation Additions (Add'l + Planned)	606	3,694	5,288	7,345	9,653	12,076
Projected Non-Peaking Gen. Additions (62% of all Additions)	376	2,290	3,278	4,554	5,985	7,487
Est. Heat Rate of Non-Peaking Gen. Additions (btu/kWh)	7,196	7,196	7,196	7,196	7,196	7,196
Projected Peak Natural Gas Usage (MMcf/day)	**65**	**395**	**566**	**786**	**1,034**	**1,293**

Assuming all of the incremental capacity requirements in the NYCA are met by generation, CEA expects that all such generation will be natural gas-fired. This assumption was made based on the following facts: (i) environmental restrictions associated with coal and oil-fired generation will likely preclude larger facilities fired by these fuel types to be constructed; (ii) it is highly unlikely that Long Island would construct new nuclear generation considering the problems experienced with the Shoreham nuclear facility in the past;[48] and (iii) while LIPA has pushed for a diversification of energy sources, including renewable energy sources such as the new wind farm awarded in its 2004 RFP, such projects are typically relatively small in size and not capable of meeting a significant portion of the future electric demand.

As presented in Table II-10, it was assumed that the 62% of the projected incremental capacity is non-peaking generation resources and will likely purchase long-term firm pipeline capacity. Also, incremental capacity additions projected for New York were assumed to have a heat rate of 7,196

48 KeySpan's chairman recently stated that both coal and nuclear power are "ruled out" for Long Island as potential future electric generation choices (New York Times, August 7, 2005).

btu/kWh. This resulted in a projected need of approximately 566 MMcf/day of additional pipeline capacity required by 2015, which grows to 1,293 MMcf/day of incremental pipeline capacity required by 2030.

2. New Jersey, Pennsylvania and Mid-Atlantic–Other

a. Electric Demand/Supply Balance

In order to determine the projected electric demand/supply balance in New Jersey, Pennsylvania, and the Mid-Atlantic–Other region (i.e., District of Columbia, Delaware, Maryland, and Virginia), CEA utilized certain demand data as reported by PJM in its 2006 Load Forecast Report[49]. Specifically, CEA utilized the forecasted summer peak load for the PJM Mid-Atlantic geographic zone (i.e., New Jersey, Delaware, the District of Columbia, Pennsylvania, and Maryland) and PJM Southern geographic zones, which is comprised by Dominion Virginia Power. PJM's planning efforts established an annual installed reserve margin for the pool, which is currently 15%.[50] For each of the PJM geographic zones, CEA utilized the available data to develop a forecast of the peak electric demand including the current 15% reserve margin requirement and compared these forecasts to the available generation capacity in each PJM zone as reported by MAAC[51] and EIA[52].

As shown in Table II-11, PJM projected a summer 2006 peak demand for its combined PJM Mid-Atlantic and Dominion Virginia Power zones of 77,140 MW, growing to a peak demand in 2016 of 90,592 MW, or at a compound annual growth rate of 1.6%.[53] CEA assumed the summer peak load would continue to grow at this same rate through 2030. MAAC projected that net capacity resources (net of new generation additions and planned retirements) for the PJM Mid-Atlantic

49 PJM Interconnection, Load Forecast Report, February 2006.

50 Determination of Forecast Pool Requirement and Other Obligation Factors for PJM RTO for 2005/06 Planning Period Effective 6/1/05.

51 As of January 1, 2006, MAAC has been succeeded by Reliability*First*, a new regional council incorporating MAAC as well as two other reliability councils, the East Central Area Coordination Agreement and the Mid-American Interconnected Network. MAAC was responsible for regional reliability planning for the PJM Mid-Atlantic geographic zone and worked closely with PJM to assess the adequacy of installed generating capacity to meet expected load

52 To estimate the summer capacity located in the PJM Southern Geographic zone, CEA utilized the 2004 EIA-860 Forms: "Existing Generating Units in the United States by State, Company and Plant" to calculate summer capacity located in Virginia as of January 1, 2005 and excluded capacity already accounted for in MAAC and capacity located in Virginian counties outside of the Dominion Virginia Power service territory.

53 PJM Interconnection, Load Forecast Report, February 2006.

geographic zone of 67,812 MW for the summer of 2005, growing to 71,761 MW by 2010.[54] The PJM Southern geographic zone currently has 19,573 MW of available summer capacity and has not announced plans for new generation additions or retirements.

Table II-11: Projected Electric Generation Required in New Jersey, Pennsylvania and Mid-Atlantic–Other

(All Figures in MW, unless otherwise noted)	Summer						
Description	**2006**	**2010**	**2015**	**2020**	**2025**	**2030**	**CAGR**
NJ, PA & MID-ATLANTIC OTHER							
Projected Summer Peak Load							
PJM Mid-Altantic Geographic Zone	58,742	62,850	67,725	72,719	78,480	84,696	1.5%
PJM Southern Geographic Zone	18,398	19,883	21,864	23,895	26,233	28,800	1.9%
Subtotal	77,140	82,733	89,589	96,614	104,713	113,497	1.6%
Plus: 15% Reserve Margin	11,571	12,410	13,438	14,492	15,707	17,024	
Total Peak Load and Reserve Margin	88,711	95,143	103,027	111,106	120,420	130,521	
Projected Summer Peak Capacity							
PJM Mid-Altantic Geographic Zone	69,817	71,761	71,761	71,761	71,761	71,761	
PJM Southern Geographic Zone	19,573	19,573	19,573	19,573	19,573	19,573	
Subtotal	89,390	91,334	91,334	91,334	91,334	91,334	
Add'l Cumulative Capacity Needed to Meet 15% Reserve Margin	**0**	**3,809**	**11,694**	**19,772**	**29,086**	**39,187**	

As shown in Table II-11 above, based on the current 15% reserve margin requirement, additional capacity is forecasted to be required in the combined PJM zones by 2010, with 39,187 MW of forecasted capacity required by 2030 to meet future load growth.

b. Projected Natural Gas Requirement Associated With Incremental Peak Electric Demand

Utilizing the MAAC and PJM data to develop the projected capacity requirements reflected in the section above, CEA estimated the magnitude of the future gas demand related to gas-fired generation. Specifically, as shown in Table II-12, it was assumed for purposes of this analysis that 100% of the new generation requirement would be met by generation as opposed to transmission.

54 MAAC Response to the 2005 NERC Data Request, August 19, 2005.

Table II-12: Projected Natural Gas Demand from Incremental Generation Capacity in New Jersey, Pennsylvania and Mid-Atlantic–Other

(All Figures in MW, unless otherwise noted)	Summer					
Description	**2006**	**2010**	**2015**	**2020**	**2025**	**2030**
NJ, PA & MID-ATLANTIC OTHER						
Additional Cumulative Capacity Needed	0	3,809	11,694	19,772	29,086	39,187
% of Add'l Capacity Needed Met by Gas-Fired Generation	54%	54%	54%	54%	54%	54%
Projected Add'l Capacity Needed Met by Gas-Fired Generation	0	2,057	6,315	10,677	15,706	21,161
Projected Non-Peaking Gen. Additions (62% of all Additions)	0	1,275	3,915	6,620	9,738	13,120
Est. Heat Rate of Non-Peaking Gen. Additions (btu/kWh)	7,196	7,196	7,196	7,196	7,196	7,196
Projected Peak Natural Gas Usage (MMcf/day)	**0**	**220**	**676**	**1,143**	**1,682**	**2,266**

It was assumed that 54% of the projected incremental generation would be gas-fired. Currently, 54% of the generation under review or under construction in the PJM Mid-Atlantic and PJM Southern geographic zones is natural gas-fired.[55] Furthermore, as previously discussed, CEA assumed that non-peaking resources represent 62% of incremental gas capacity and have a heat rate of 7,196 btu/kWh. As a result and as presented in Table II-12 above, CEA is forecasting for the New Jersey, Pennsylvania, and Mid-Atlantic–Other market a need of approximately 676 MMcf/day of incremental gas demand by 2015 for the gas-fired generation segment. By 2030, the incremental demand for natural gas grows to approximately 2,266 MMcf/day.

55 Analysis of PJM Generation Interconnection Request Queues.

III. CONCLUSIONS AND FINDINGS

As discussed in the previous section, CEA is forecasting significant natural gas growth by segment (i.e., LDC and gas-fired generation) and by state/region in the defined market. Specifically, as shown by Table III-1 below, total incremental design day demand for natural gas in the Mid-Atlantic market region is forecasted to be approximately 4,311 MMcf/day by 2020 and projected to reach approximately 7,515 MMcf/day by 2030.

The demand for natural gas is not only fairly evenly distributed across the various regions but also across the different segments. Specifically, the LDC segment represents approximately 53% of the 2030 forecasted incremental design day demand for natural gas in the defined market while the gas-fired generation segment is 47% of the 2030 forecasted incremental design day demand.

Table III-1: Summary of Estimated Incremental Design Day Demand for Natural Gas in the U.S. Mid-Atlantic Market Region

(Figures in MMcf/day) Description	2009 2010	2014 2015	2019 2020	2024 2025	2029 2030
LDC Incremental Design Day Demand					
New York	240	508	693	886	1,085
New Jersey	165	343	519	702	892
Pennsylvania	128	293	465	644	829
Mid-Atlantic Other	294	495	703	921	1,150
Total Mid-Atlantic Market Region	826	1,639	2,381	3,153	3,956
Gas-Fired Generation Incremental Design Day Demand					
NYISO NYCA	395	566	786	1,034	1,293
PJM Mid-Atlantic & Southern Zones	220	676	1,143	1,682	2,266
Total Mid-Atlantic Market Region	616	1,242	1,930	2,715	3,559
Total Mid-Atlantic Market Region	1,442	2,882	4,311	5,868	7,515

In addition to the forecasted incremental design day demand for natural gas, CEA also reviewed the supply in-fill opportunities in the Mid-Atlantic region. Specifically, CEA analyzed the supply in-fill opportunity in the defined market as a result of the forecasted decline in certain U.S. gas supply basins and the forecasted reduction in Canadian natural gas that is available for export to the U.S. The supply in-fill opportunity is estimated by CEA to be approximately 543 MMcf/day by 2010 and approximately 1,031 MMcf/day by 2030.

In other words, the requirement for new natural gas supply resources is not only driven by the increasing demand for natural gas in the LDC and gas-fired generation segments but also as a result of the decreasing availability of certain natural gas supply sources. Therefore, the total natural gas requirement (i.e., incremental design day demand and supply in-fill) for the defined market is approximately 4,921 MMcf/day by 2020 and 8,546 MMcf/day by 2030.

Finally, to illustrate the impact of the proposed Sparrow Point LNG project, CEA compared the forecasted total natural gas demand discussed above, including projected supply in-fill opportunities, to the expected delivery volumes for the Sparrow Point LNG/Mid-Atlantic Express Pipeline facilities. In other words, Table III-2 below summarizes the projected additional design day demand in the defined market after the inclusion of the 1,500 MMcf/day from the Sparrow Point LNG and Mid-Atlantic Express Pipeline.[56]

Table III-2: Net Incremental Design Day Demand

(Figures in MMcf/day) Description	2005 2006	2009 2010	2014 2015	2019 2020	2024 2025	2029 2030
Incremental Design Day Demand	65	1,442	2,882	4,311	5,868	7,515
Plus Supply In-Fill	349	543	146	610	853	1,031
Less Proposed Sparrows Point LNG Terminal	0	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)
Total Net Incremental Design Day Demand	**414**	**485**	**1,528**	**3,421**	**5,222**	**7,046**

As shown by Table III-2, if the proposed Sparrows Point LNG/Mid-Atlantic Express Pipeline facilities satisfy 1,500 MMcf/day of the projected design day demand, the defined market would still have an incremental natural gas requirement of 3,421 MMcf/day by 2020 and approximately 7,046 MMcf/day by 2030. In other words, by the 2020 time period the forecasted incremental design day demand and supply-in fill of approximately 4,921 MMcf/day will not only require the 1,500 MMcf/day from Sparrows Point but will also require approximately two incremental natural gas supply projects that are larger than the size of Sparrows Point.

56 The Sparrows Point LNG and Mid-Atlantic Express Pipeline are assumed to be in-service as of 2010.

APPENDIX B

EMAIL DOCUMENTING DISCUSSIONS WITH MARYLAND AGENCIES RESPONSIBLE FOR MANAGING FEDERALLY FUNDED HIGHWAYS

Phillips, Steve

Subject: FW: FERC data request - RR 10

-----Original Message-----
From: Rick Sheckells [mailto:rsheckells@ecologixgroup.com]
Sent: Monday, September 18, 2006 9:56 AM
To: Chris Diez
Cc: Ed Cahill; Scott Taylor; Kent Morton
Subject: FERC data request - RR 10

FERC Comment:
Provide copies of letters, faxes, e-mails, memos and phone logs of any meetings/discussions with the U.S. Department of Transportation concerning the co-location of the send-out pipeline with any interstate of federal (or federally funded) highway.

Response
There has been no direct contact with the U.S. Department of Transportation concerning the co-location of the send-out pipeline with any interstate of federal (or federally funded) highway. However, the State agencies responsible for managing federally funded highways in Maryland are the Maryland State Highway Administration (SHA), an agency of the Maryland Department of Transportation that receives funding from Maryland's Transportation Trust Fund, and the Maryland Transportation Authority (MdTA), an authority chaired by Maryland's Transportation Secretary that operates under a separate trust fund. AES provided briefings to senior personnel of both of those agencies as follows:

Maryland Transportation Authority
The MdTA is responsible for the sections of Interstate 95 (from the Baltimore Beltway (I-695) north into Harford County) within the right-of-way of which AES would potentially locate pipeline. On **January 20, 2006**, AES met with MdTA Executive Secretary Trent Kittleman, and Deputy Executive Secretary Joseph Waggoner, and Deputy Director of Strategic Development David Greene. At this meeting AES provided a project overview and discussed the interest of the Authority in allowing access. The Authority is also responsible for the Francis Scott Key bridge which crosses the Patapsco River west of the proposed terminal site, and the William Preston Lane Memorial Chesapeake Bay bridge under which LNG vessels calling the Sparrows point terminal would pass. Senior Authority people suggested a follow-up briefing with staff in order that various departments could understand the project and its potential affects on agency personnel and facilities. On **March 14, 2006**, AES provided a detailed briefing to senior managers from the MdTA. Those managers included the Executive Director of Engineering and Construction Management, Director of Engineering, Director of Operations for the Authority Police, Deputy Director Capital Planning, Deputy Director Strategic Development, Administrator FSK Bridge, and Public Affairs Officer. These meetings resulted in the initiation of a right-of-entry agreement for survey purposes, and the Authority's participation in the WSA process.

Maryland State Highway Administration
The SHA is responsible for sections of Interstate-695 (the Baltimore Beltway) from Dundalk to I-95 within the right-of-way of which AES would potentially locate pipeline. On **February 14, 2006** AES met with SHA Deputy Administrator Doug Simmons and Right of Way Chief Chris Larson. The result of this meeting was the initiation of a right-of-entry agreement for survey purposes.

Maryland Department of Transportation
The MDOT is the parent agency for all transportation modes in Maryland. On **March 2, 2006**, AES met with three senior officials at MDOT to provide a project overview. Those officials included Special Assistant to the Secretary Al Zawicki, Director of Engineering, Procurement and Emergency Services John Contestabile, and Homeland Security specialist Mike Collins. This briefing resulted in MDOT attendance at several subsequent open house meetings, and participation in the WSA process.

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