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To Whom It May Concern,

At the request of Invenergy LLC ("Invenergy"), PA Consulting Group, Inc. ("PA") prepared this memorandum describing PA's analysis of Invenergy's proposed [redacted] MW summer-rated Pascoag Energy Center natural gas-fired combined cycle development project (the "Project" or "PEC"), to be located in Burrillville, Rhode Island and which would operate in the New England electricity market ("ISO-NE"). This memorandum summarizes PA's analysis, and provides an overview of PA's underlying market assumptions and modeling methodology as well as PA's projections of PEC's operations and energy margins.

Background

Figure 1: PEC's Location in ISO-NE[1]

PEC is a proposed summer-rated [redacted] MW natural gas-fired combined cycle power plant to be located in Burrillville, Rhode Island. See Figure 1. The Project has a planned commercial online date of June 2019 and would utilize [redacted]. The facility is projected to have a summer full load heat rate of [redacted] Btu/kWh and be interconnected into the Rhode Island zone of the ISO-NE power market. See Appendix Table A-5 for an overview of PEC's assumed dispatch characteristics.

As part of its work, PA developed a monthly 20-year forecast (2019 through 2038) of the ISO-NE power market and a 20-year forecast (2019 through 2038) of PEC's operations and cash flows. Unless otherwise noted, all numerical values are in nominal dollars in this memorandum.[2]

Modeling methodology overview

PA has a robust, well-developed, and industry-tested fundamental modeling process, including its proprietary stochastic dispatch optimization, capacity compensation, environmental, renewable, and valuation models along with the use of production cost, transmission, and natural gas models that are operated by PA's subject matter experts and populated with PA proprietary data. See Figure 2.

PA utilizes [redacted] for its production cost modeling in order to dispatch generation units to minimize total system cost, and PA analyzes both fixed and future capital costs required to meet

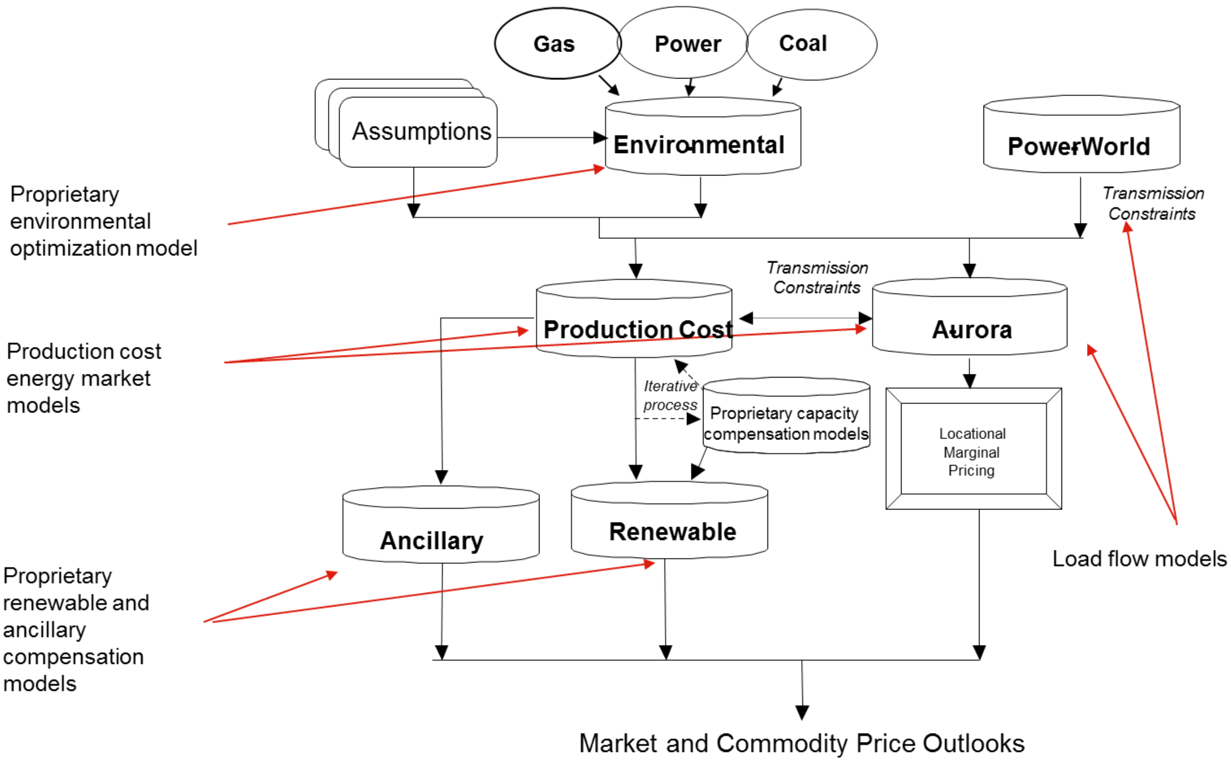
[1] Source: PA Consulting Group and copyrighted material excerpted from Ventyx's *Velocity Suite* Energy Map.
[2] PA assumes an inflation rate of 2.2% per annum.

[redacted] [redacted]

electric demand and ensure system reliability. The latter analysis results in a projection of incremental compensation required to maintain reliability, which existing generation should be measured against. PA's proprietary environmental optimization model integrates the natural gas-power-coal sectors, as well as the coal generator capital expenditure versus coal selection and resulting emission price, paradigms.

PA also utilizes its proprietary stochastic model to assess specific generator operations and economics relative to the electric system and under power purchase agreements, as necessary, as well as assess financial hedges and fuel transportation rights.

Figure 2: PA's Fundamental Modeling Process[4]



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3 [redacted]

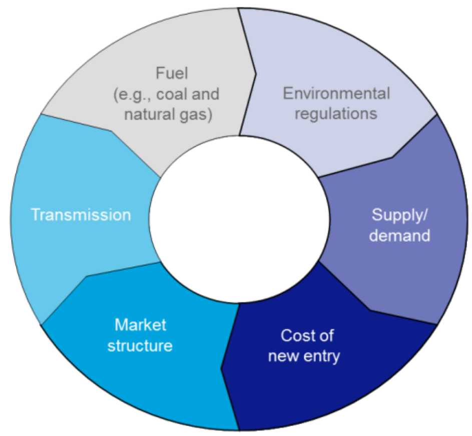
4 The illustration in this figure does not include PA's stochastic dispatch model, which was used to forecast hourly (4-hour block basis) Project-level production and energy and ancillary margins.

Key modeling assumptions

PA views power markets within the context of six key value drivers (i.e., major assumptions) that are directly integrated into PA's fundamental market modeling process. These key drivers include market structure, fuels (i.e., natural gas and coal), environmental regulations, supply and demand, cost of new entry, and transmission. See Figure 3.

i. Market structure

Figure 3: Key Market Drivers



As one of the first power markets to institute an ISO, the New England power market is among the most developed energy markets in the United States. ISO-NE operates as a fully functional RTO, coordinating, monitoring, and directing the operation of the market's transmission system as well as its power generating facilities. The New England power market covers the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and is divided into eight load zones.

PA's analysis assumes all current ISO-NE energy, ancillary and capacity market rules as its base case view.

ii. Fuels

Fuel prices impact the projected dispatch cost of thermal power generating assets as well as the resource planning decisions of retail electric providers. The fuel of primary importance in ISO-NE is natural gas (and, to a lesser extent, fuel oil).

Despite having multiple procurement options and being located less than 200 miles away from the Marcellus shale play, ISO-NE is among the most gas-constrained regions in the country. Recent factors, including declining Eastern Canadian production and reduced Liquefied Natural Gas ("LNG") deliveries due to the expiry of long term supply contracts, have exacerbated winter price spikes as evidenced in the winters of 2012/13 and 2013/14. During the shoulder and summer months, there is typically sufficient pipeline capacity on the interstate pipelines to meet regional demand.

Historically, natural gas prices in major Northeast markets have experienced severe seasonal volatility. In the past several years, price volatility in ISO-NE – specifically Boston – has increased. However, other Northeast markets, such as New York and New Jersey, have decreased in volatility. This decline is attributable to several natural gas pipeline projects, such as Spectra's NY-NJ project and the proposed Constitution pipeline, which have and will alleviate some of the persistent regional transportation constraints. While these projects will alleviate historic constraints into the broader New Jersey and New York City market, limited progress has been made on expansions further downstream into ISO-NE creating a widening price differential between these markets during constrained winter periods.

As more takeaway capacity is brought to ISO-NE through additional expansions, further year-round basis declines can be expected – driven primarily by basis reductions during winter months. While the basis differential is expected to narrow in the long-term, PA expects that Algonquin Citygate (the natural gas pricing point of primary importance in ISO-NE) will continue to trade at a premium. See Table 1.

[redacted]

a. PEC fuel sourcing

[redacted]

This supply arrangement affords PEC the ability to source approximately [redacted]%, on average, of its natural gas needs directly from the Marcellus at Leidy-type pricing, which is expected to continue trading at a significant discount to Algonquin Citygate throughout the study period, driven by its location in the heart of the Marcellus shale play. See Table 2. On average, this supply arrangement, excluding fixed transport charges, results in the Project sustaining an approximately [redacted] discount in delivered natural gas costs compared to natural gas-fired competitors taking [redacted]% of deliveries off of the Algonquin pipeline.

PA's base case reflects this proposed fuel procurement strategy. Energy margin projections (shown in Figure 6) are net of associated fixed transport charges (assumed to be approximately [redacted]Dth based on discussions between Invenergy and owners of the Millennium and Algonquin pipelines).

[redacted]

iii. Environmental regulations

Power generating assets are currently subject to local, state, and federal laws for emissions, including sulfur dioxide ("SO_2"), nitrogen oxide ("NOx"), particulate matter ("PM"), mercury ("Hg") and other hazardous air emissions. Federal regulation by the EPA is currently in various stages of review to further limit SO_2, NOx, particulate matter, mercury and other hazardous air emissions as well as coal combustion ash disposal and plant water intake/discharge practices. Meanwhile, legislation to limit greenhouse gas ("GHG") emissions (including CO_2) has all but stalled at the Congressional level, while the EPA continues to take steps in developing federal GHG oversight and limits for new and existing facilities. In the absence of federal legislation, regional GHG programs in the United States have been implemented, but in limited fashion. While directly or indirectly affecting all power generators, these regulations disproportionately affect coal-fired resources.

PA's analysis takes into consideration all major national and regional environmental regulations applicable to power generation. Key regulations include:

[redacted]

Sulfur dioxide, nitrogen oxides and particulate matter. PA's analysis assumes Cross-State Air Pollution Rule ("CSAPR") regulations beginning in 2015. It is PA's assumption that CSAPR (or any future replacement) regulations will be primarily implemented at the state level (or company-owned portfolio level) and will likely not result in widespread interstate trading, although some small amount of regional trading may emerge. The practical effect on the industry, except on the periphery, is likely to be relatively minimal when compared to the impact of other current and pending EPA rules.[5] See Appendix Table A-2(b).

Mercury and air toxics. In December 2011, the EPA published final rules to reduce emissions of mercury and other air toxics, utilizing a Maximum Achievable Control Technology (“MACT”) standard, called MATS. In addition to mercury, the rule covers other hazardous air pollutants, including other heavy metals and acid gases. In addition to federal regulation, several states have also enacted state-specific regulations to address mercury emissions from coal power generating assets. PA assumes the EPA’s current MATS rule regulation beginning in the 2015-2016 timeframe, with the possibility of delay on a plant-by-plant basis for an additional year, as well as current state regulations governing mercury emissions.

Water intake and discharge. Sections 316(a) and 316(b) of the Federal Water Pollution Control Act (also known as the Clean Water Act) require the EPA to regulate cooling system thermal discharge and intake structures at power plants. In May 2014, the EPA published a final rule that covers existing facilities that withdraw at least 25% of their water from an adjacent body of water exclusively for cooling purposes and have a design intake flow of greater than 2 million gallons per day. While the final rule is generally flexible with regards to compliance options, in some instances it may require existing plants to replace once-through cooling systems with more expensive closed loop systems.

GHG regulation. After multiple failed attempts by Congress to legislate a national greenhouse gas program, the EPA has moved forward with a multi-pronged approach to address GHG emissions. In September 2012, the EPA proposed new rules for the New Source Performance Standard (“NSPS”) program that would essentially halt all new development of coal that does not include carbon capture and sequestration.[6] Additionally, in June 2014, the EPA proposed the Clean Power Plan, which seeks to reduce carbon emissions from *existing* power generation by 30% in 2030 when compared to 2005 emissions. Unsatisfied with federal efforts to regulate GHG emissions, some states have moved forward with their own programs. The Regional Greenhouse Gas Initiative (“RGGI”), which took effect in 2009, calls for a 10% reduction in greenhouse gas emissions from 2005 levels by 2018 for the nine participating Northeastern states.[7] Based on the current and projected level of federal activity regarding GHG regulations, PA does not assume a

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[5] Given the limited trading anticipated under the CSAPR program, PA does not incorporate specific CSAPR emission allowance prices in dispatch costs in 2015 or beyond.

[6] While EPA regulatory rules regarding GHG emissions will limit coal-fired builds going forward, PA’s analysis does not assume incremental coal-fired additions over and above those considered to be ‘firm’ additions.

[7] The nine Northeastern states participating in RGGI are Connecticut, Delaware, Maryland, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey withdrew from the program at the end of 2011, however, the New Jersey State Senate passed a resolution in October 2014 that could potentially override the state’s withdrawal from RGGI. As such, there is the potential that New Jersey could re-join RGGI in the future, although the resolution (and any impact thereof) still has multiple hurdles to pass before New Jersey could re-join the program. In June 2012, a New Hampshire law went into effect that would withdraw the state from RGGI if two New England states (or 10% of RGGI’s New England load) leave the cap-and-trade program.

[redacted]

congressionally-mandated or other federal GHG cap-and-trade (or tax) program within the study period. However, PA does assume RGGI pricing for Rhode Island (as well as the rest of the ISO-NE states). See Table 3.

[redacted]

iv. Supply and demand

The supply and demand balance in power markets is one of the most critical factors in determining power generating asset value, particularly for assets that depend on capacity revenues. See Table 4 for peak demand and energy growth rates for ISO-NE, which are based on the 2015 CELT Load Report through 2024 and use a 5 year average growth rate for the remainder of the study period.

[redacted]

Table 4: Average Annual Growth Rates (2019-2038)[8]

Market	Peak Demand	Energy
ISO-NE	1.2%	1.0%

PA assumes that ISO-NE will have nearly [redacted] GW of supply when PEC enters the market in 2019 (inclusive of PEC) and for the market to be short supply to meet peak demand plus reserve margin in 2024. See Appendix Table A-3 for an overview of PA's supply and demand assumptions.

v. Cost of new entry

The cost of new entry is generally considered as the cost to build new power generation, incorporating financial assumptions such as debt/equity ratio, interest rate on debt, return on equity, etc., in addition to construction costs. It is also referred to as a capital cost. A power market's capital costs help define the premium a market places on capacity, and the overall compensation levels achievable in the market. See Table 5 for the cost of new entry assumptions.

Table 5: 2024 ISO-NE Cost of New Entry (2024$)

[redacted]

iv. Transmission

The New England transmission system has evolved into a well-integrated network. Typical power flows in the area are from north to south and from east to west. With the recent completion of the New England East-West Solution ("NEEWS") transmission upgrades, congestion at nodes on the 345 kV system near Sherman Road has been minimized. For example, over the last 12 months the congestion component of the Rhode Island zone day ahead market price and Ocean State Power's nodal price has been zero for 90 percent of the hours. PA expects these minimal congestion conditions to be maintained over the projection period and expects future prices for the Project to be at a small discount [redacted] to Rhode Island zone prices. PA's analysis of the Project reflects this small discount in energy pricing at the plant's busbar.

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[8] Peak demand and load growth numbers through 2024 are from the 2015 CELT Load Report. 2025-2038 uses a 5 year average growth rate.
[9] The installed capital cost represents the long-term cost of new entry, and includes interest during construction.

[redacted]

Market projections

This section provides an overview of the market projections (e.g., market spark spreads and heat rates) for the ISO-NE power market, based on the market assumptions described above.

i. Clean market spark spreads

Clean market spark spreads[10] are a primary indicator of a combined cycle power plant's earnings potential in a wholesale market like ISO-NE. PA's analysis projects on-peak spark spreads in ISO-NE Rhode Island to rise slightly over the study period largely due to increasing natural gas prices. See Figure 4. Occasional dips in clean market spark spreads largely reflect new generation entering the market and depressing power prices. Off-peak spark spreads are projected to remain relatively flat.

[redacted]

10 [redacted]

[redacted]

ii. Clean market heat rates

On-peak clean market heat rates[12] measure the efficiency of the marginal unit setting power prices in a given region. In ISO-NE, on-peak market heat rates are projected, as shown in Figure 5, to decline from current levels largely driven by more efficient natural gas generation entering the market. Off-peak market heat rates are projected to remain mostly flat.

[redacted]

On-Peak
Off-Peak

Asset projections

With a baseload technical summer-rated full load heat rate of [redacted] Btu/kWh, PEC is projected to be one of the most efficient combined cycle power plants in ISO-NE when it comes online in 2019. This is reflected in the Project's capacity factor of [redacted]% in its first full year of operations in 2020, as shown in Figure 6. Capacity factors are projected to decline slightly over the study period to [redacted]% in 2038 due to decreasing market heat rates.

Energy contribution margins (not including capacity revenues, but including ancillary margins[14]) are expected to rise from [redacted] million in 2020 (PEC's first full year of operations) to over $[redacted] million by 2038. The increase in energy margins is driven by improved spark spreads, which is largely driven by increasing natural gas prices (as described in the previous section).

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[12] [redacted]

[13] Source: PA Consulting Group.

[14] The ancillary services revenues reflected in the pro forma represent ancillary services value incremental to energy margins. Essentially, this means that the projected ancillary 'revenue' is actually ancillary 'margin' that can be earned over and above day-ahead energy market sales. PA's ancillary projections for the Project reflect a combination of regulation and spinning sales.

As noted previously, PA's projections do not include capacity revenues.

[redacted]

15 2019 is a partial year (June through December).
16 Source: PA Consulting Group.

A APPENDIX: PROJECTION AND ASSUMPTION DETAIL

This section provides an overview of PA's market analysis projections, including key input assumptions. All values, unless otherwise noted, are in nominal dollars, based on an inflation rate of 2.2%.

[redacted]

[17] On-peak East Hours [redacted]%
Off-peak East Hours [redacted]%
[18] Source: PA Consulting Group.
[19] Clean spark spreads and market heat rates normalize for the assumed price of CO_2. Clean spark spreads and market heat rates subtract the variable CO_2 cost of a [redacted] Btu/kWh combined cycle.

[redacted]

A.2 Commodity and emission price projections

[redacted]

[20] <<< Incorporates forwards as of 4-30-15.
[21] Source: PA Consulting Group.

[redacted]

[redacted]

[22] <<< Incorporates forwards as of 4-30-15.
[23] Source: PA Consulting Group.
[24] a [redacted]
[25] Source: PA Consulting Group.

[redacted]

A.4 Firm capacity additions and retirement summary

Table A-4(a): Firm Thermal Capacity Additions – New England[26,27]

[redacted]

Table A-4(b): Firm Retirement Summary – New England[28,29]

[redacted]

[26] If a power generating asset is not online by August 1st of a given year, it does not count towards market reliability until the following year.
[27] Source: PA Consulting Group.
[28] "Retirement Year" corresponds to the year a power generating asset retirement affects the reserve margin referenced in the Supply-Demand tab. If a plant does not retire by August 1st of a given year, it does not impact the Supply-Demand table until the following year.
[29] Source: PA Consulting Group.

[redacted]

A.5 Operating dispatch characteristics

[redacted]

A.6 Contribution margins

Table A-6(a) and A-6(b) provide the details of PA's 15-year projections of PEC's operations and contribution margins. Note that 2019 is a partial year June through December.

[redacted]

[30] Source: Invenergy.
[31] 2019 is a partial year (June through December).

[redacted]

[redacted]

[redacted]