WRIGHT & TALISMAN PC

1200 G Street, N.W.
Suite 600
Washington, D.C. 20005-3802
202.393.1200
Fax 202.393.1240
www.wrightlaw.com

February 11, 2011

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

Re: *PJM Interconnection, L.L.C.*, Docket No. ER11-__-000

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, and the Commission's regulations, 18 C.F.R. part 35, hereby submits for filing revisions to the PJM Open Access Transmission Tariff ("Tariff") to update and simplify the Reliability Pricing Model's minimum offer price rule and to conform that rule to the Commission's recent precedents on similar rules in New York and New England. PJM also proposes to add to the Tariff a date certain for PJM to file changes to RPM's new entry price adjustment provision, as determined necessary after a stakeholder process, to address concerns that such provision does not currently provide sufficient revenue assurances to support new entry. The enclosed tariff changes reflect an effective date of April 13, 2011, which is 61 days after the date of this filing.

I. Introduction

The Reliability Pricing Model ("RPM") is the set of rules by which PJM obtains commitments of capacity to meet the PJM Region's reliability needs through auctions conducted three years before the year for which the capacity is needed (i.e., the Delivery Year). The annual RPM Base Residual Auctions therefore provide both certainty of supply three years into the future and a forward pricing signal and revenue stream to support and incent investments in capacity resources (of all types) where needed on the system to meet reliability goals.

RPM has shown notable success in meeting that design objective. RPM has encouraged investment needed to maintain both existing generation and demand response resources, as well as investment in new resources, including incremental upgrades to existing generators, new energy efficiency projects, new demand-side resources and new generation resources. PJM's report on the most recent Base Residual Auction found that 33,090 megawatts of capacity resources were offered into that auction that would not have been available absent the implementation of RPM. Based on similar evidence of capacity increases in response to RPM, the U.S. Court of Appeals for the District of Columbia Circuit recently found that the

Commission was well-entitled to conclude that "the RPM was an appropriate tool for increasing reliability in electricity markets, [and] that the RPM did precisely what it was intended to do."[1]

To ensure continued economic investment in existing and new resources, RPM must continue to send accurate price signals. Accurate price signals, correctly indicating where new entry is needed on the system, and accurately conveying the cost of that new entry, provide information that is essential both for private bilateral contracts and for public policy initiatives. RPM's market rules therefore must ensure that new entrants are not permitted to exercise market power to increase clearing prices above the competitive cost of new entry. Those rules also must ensure that market participants cannot use uncompetitively low new entry offers to suppress clearing prices, which can deter new entry even in parts of the system where it may be required.

To that end, the 2006 settlement that established the Reliability Pricing Model ("RPM") added a Minimum Offer Price Rule ("MOPR") to address a concern that some market participants "might have an incentive to depress market clearing prices by offering some self-supply at less than a competitive level."[2] The Commission accepted that aspect of the settlement, finding it "a reasonable method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self supply."[3] The Commission has approved similar provisions, for essentially the same purpose, for the capacity markets of the New York ISO and ISO-New England, and has provided additional guidance on the proper design of a MOPR-type provision in its orders on those regional transmission organizations ("RTOs"). Moreover, in 2009, the Commission rejected an effort to replace the MOPR with an alternative approach that would have allowed the market monitor to determine whether new entry offers are uncompetitively low, and reasserted its "concern that uneconomic entry can be used by certain buyers to depress market clearing capacity prices."[4]

As discussed in more detail below, the current MOPR:

- Determines Net Asset Class Cost of New Entry Values for typical combustion turbine and combined cycle new plant configurations;

- Discounts those values, using a percentage factor, to identify a lower bound on a reasonable new entry offer;

---

1 *Maryland Pub. Serv. Comm'n v. FERC*, No. 09-1296 (D.C. Cir. Feb. 8, 2011), slip op. at 5.

2 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 103 (2006).

3 *Id.* at P 104.

4 *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 191 (2009) ("*March 2009 Order*").

- Permits sellers with new entry offers that fall below those screens to seek a determination from the Commission that their offer is nonetheless appropriate;

- Assesses whether a new entry offer would reduce price substantially (i.e., 20-30%) in the RPM auction, and applies mitigation only if it would have such an impact;

- Applies only if the capacity market seller (or its affiliate) is "net short" in the auction, i.e., buying substantially more than it sells;

- Applies only in the first auction that a planned generation resource is offered, regardless of whether the resource clears in that auction;

- Excepts from the MOPR new entry that is pursuant to a state mandate under certain conditions; and

- If all of its conditions are met, re-prices the sell offer to a higher level and re-runs the relevant auction.

PJM has conducted seven Base Residual Auctions, covering seven Delivery Years, since RPM was implemented, and the MOPR has never been triggered. PJM is concerned that, despite the potential for below-cost bidding to adversely affect the capacity market, the MOPR in its current form may never be applied, and may not be adequate to serve the purposes for which it was approved by the Commission. For example, the Commission has seen that state programs intended to support new generation entry through out-of-market payments to the generator can raise the price-suppression concerns that MOPR-type provisions are intended to address.[5] However, the current "net short" requirement likely puts such programs beyond the reach of PJM's MOPR, unless the buyer and seller in such contracts happen to be affiliates. This is significant, as some states in the PJM region have begun to implement generation procurement programs similar to the state programs in New England that have prompted ISO-New England, Inc. to substantially revise its MOPR-type provision.

Others have taken note of these developments. On February 1, 2011, the PJM Power Providers Group ("P3") filed a complaint with the Commission under FPA section 206 in Docket No. EL11-20-000 contending that the current MOPR is unjust and unreasonable, and proposing extensive changes to the MOPR. The P3 Complaint cites a recently enacted New Jersey capacity procurement statute[6] and warns that "uneconomic entry" into PJM pursuant to that state law is "imminent." The P3 Complaint therefore requests fast-track processing, and asks the

---

5 *See, e.g., ISO-New England, Inc.*, 131 FERC ¶ 61,065, at P 77 (2010) (directing parties to address treatment of resources receiving out-of-market payments made to support resource adequacy or other public policy objectives).

6 S. 2381, 214th Leg. (N.J. 2011).

Commission to issue an order revising the MOPR prior to the next RPM Base Residual Auction, which is scheduled for May 2011. The Commission issued its notice of the complaint on February 4, 2011 and set February 22, 2011 as the deadline for PJM's answer and any other interventions, comments, or protests.

As will be evident from this filing, PJM generally agrees that the current MOPR is flawed and in need of reform. The current MOPR's low asset-class reference values, substantial discounts off those values, requirement for a large impact on clearing prices, application only to the very first time a new entry unit is offered in an auction, and numerous ambiguities, along with the net short requirement, all raise serious questions about the effectiveness of PJM's MOPR in its current form. Moreover, as discussed in this filing, PJM's MOPR does not reflect the Commission's precedent on MOPR-type provisions of other RTOs issued after the Commission's acceptance of the 2006 RPM settlement.

PJM disagrees, however, with some of the changes sought by the P3 complaint. Therefore, while PJM will timely answer the P3 complaint, the most effective means of presenting for Commission consideration PJM's alternative approach to MOPR reform is through an FPA section 205 filing such as this.

Given these circumstances, while PJM would not normally conduct a stakeholder process on PJM's answer to a complaint, PJM arranged an informational conference call on this matter for its stakeholders on February 9, 2011. Over 270 individuals joined the call. On the conference call, PJM and the Independent Market Monitor ("IMM") for the PJM Region explained their common position that the current MOPR is inadequate. PJM explained that its response to the complaint would rely on a section 205 filing to set forth PJM's alternative approach to addressing the concerns described in the complaint, and outlined the principal elements of that alternative approach. Both PJM and the IMM then responded to questions from stakeholders.

PJM also advised its stakeholders that, given the P3 Complaint's request for action before the May 2011 auction, PJM planned to submit its section 205 filing within a matter of days. PJM does so now, in part to enable the Commission, if it chooses, to act on these Tariff changes before the upcoming auction. Given the MOPR's current flaws, that is PJM's preferred course. As states in the PJM region, which continue to have an important oversight role in the procurement of generation,[7] move forward with their procurement programs, all parties need a clear idea of the parameters of RTO capacity programs that may affect their plans. Commission action on this filing will put needed MOPR reforms in place before generation developers and load serving entities enter into financial commitments under the developing state programs.

---

[7] There remain many areas of discretion concerning capacity procurement left to the states, as the Commission recognized in connection with the New York ISO's MOPR-type provision. *New York Independent System Operator, Inc.*, 124 FERC ¶ 61,301, at P 38 (2008). For example, nothing in this filing affects a state's decision to procure renewable generation, including off shore wind, in order to meet a state RPS requirement

PJM also notes that it is not proposing in this filing any phasing of the MOPR tariff changes. Each change PJM proposes in this filing is needed to correct a shortcoming in the current MOPR. If the Commission were to act on only some of these changes before the May 2011 auction, that would leave some of the acknowledged deficiencies of the MOPR in place. Accordingly, the MOPR changes PJM proposes in this filing are a coordinated package, and PJM asks that the Commission approve them as a coordinated package.

Lastly, PJM notes that while this filing discusses in detail a number of Tariff changes, all of those changes are to a single section of the RPM Tariff rules—the MOPR—with a single focus and purpose—preventing uneconomically low sell offers from new entry generation plants. This is not an occasion for a broad review or overhaul of RPM, nor should this proceeding (or the proceeding on the P3 complaint) become a vehicle for any party to push upon the Commission any concern they have with any other aspect of RPM. PJM has an active stakeholder process for ongoing review and refinement of all of its market rules, including RPM. Indeed, PJM is already subject to two tariff obligations to review with stakeholders this year the performance of RPM to date and whether any changes should be made to the key parameters of the Variable Resource Requirement ("VRR) Curve that is used to clear the RPM auctions.[8] Following the reviews and reports required by these Tariff provisions, PJM will work with stakeholders to determine what, if any, changes are needed to the affected aspects of RPM.

In the remainder of this transmittal, PJM discusses in detail the shortcomings of the various elements of the current MOPR, and PJM's proposed solutions to each of those deficiencies. PJM also discusses two related areas for consideration this year of Tariff changes that can facilitate new entry. PJM proposes to set itself a deadline in the Tariff for filing with the Commission any changes to RPM's New Entry Price Adjustment resulting from a stakeholder process this year. PJM also proposes to review with stakeholders this year possible changes to PJM's generator interconnection process to render that process more responsive to needed new entry.

II. Description of, and Justification for, Proposed Tariff Changes

A. Updated Reference Values

The MOPR uses a "Net Asset Class Cost of New Entry" as a reference to indicate whether a new entry sell offer is uncompetitively low. The current MOPR provision on this reference value, however, is understated, outdated, and ambiguous. It uses discounted 2008

8 Tariff Attachment DD, section 17.6, requires PJM to "prepare, provide to Members, and file with FERC an assessment of the performance of the Reliability Pricing Model" within six months after the end of the fourth Delivery Year, i.e., by November 30, 2011; and section 5.10(a) requires PJM to review the RPM demand curve shape and key inputs (i.e., the estimates of the cost of a new peaking plant to enter the market, and the process for estimating the energy market revenues such a plant can expect to earn) and report to stakeholders by September 1, 2011 whether PJM has determined any changes are needed to those elements.

values for the gross cost of new entry ("CONE"), implies incorrectly that the gross CONE value is a net value, and does not explain how the energy and ancillary service revenue amount needed to calculate a net value is determined. PJM is now correcting each of these infirmities.

1. Gross CONE Values.

The MOPR currently states a reference value for a combustion turbine plant as \$96,485/MW-year. The April 2009 compliance filing that supplied this value describes it in terms of the gross cost of new entry.[9] However, the gross CONE level (also based on a combustion turbine plant) that PJM is using as an input to the Variable Resource Requirement ("VRR") Curve (i.e., the demand curve) in its upcoming 2011 RPM auction is considerably higher, ranging from \$128,226/MW-day to \$138,646/MW-day. Similarly, the MOPR reference value for a combined-cycle plant, also characterized in April 27, 2009 compliance filing as a gross CONE number, is well below recent gross CONE estimates for a CC plant, such as that in the State of the Market report for the PJM Region.[10]

PJM therefore is updating these values for the upcoming May 2011 RPM auction. For the CT plant, PJM will use the same values produced under other approved provisions of its Tariff for the VRR Curve parameters for that auction. These values are indexed to track changes in construction costs, and vary by location to reflect differences in labor, land, tax, and other costs by sub-area within the PJM Region. As required by its Tariff, PJM posted these CT CONE values, along with other RPM auction parameters, on February 1, 2011. PJM now proposes to state these values in the MOPR provision for use in the upcoming auction, to ensure consistency between the CT estimate in the MOPR and the CT estimate in the VRR Curve.

For the combined-cycle plant, PJM has commissioned an updated estimate of the gross CONE for a representative CC plant. The estimating method used for this purpose is the same as that which underlies each of the gross CONE values the Commission previously has accepted both for RPM's demand curves and for the prior and current MOPR reference values. That same estimating method also has been used to estimate generator revenue requirements in the PJM Region State of the Market Reports. As explained in the attached affidavit and report of Mr. Raymond M. Pasteris (Attachment C to this filing), he prepared the new CC CONE estimate in the same manner as his prior CT and CC CONE estimates for RPM, i.e., determining the fixed costs to install and operate a new power plant at various locations within the PJM Region, based on plant configurations typical of those in the region. As shown in his report, his estimate of the

---

9 *See* PJM's April 27, 2009 compliance filing in Docket No. ER09-412-000 ("April 2009 Compliance Filng"), at 3-5.

10 The MOPR reference value is \$117,035/MW-year, whereas the 2009 SOM estimated the gross annual revenue requirement for a CC plant as \$173,174/MW-year. *See* 2009 State of the Market Report for PJM, at 163, available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec3.pdf

annual revenue requirements for such plants is supported by detailed underlying estimates of the "plant-proper" capital costs, plant fixed operating and maintenance ("O&M") expenses, and air quality and other permitting costs, each prepared by subcontractors with specialized knowledge of those cost components.

While this is the same method underlying the current MOPR CC values, those current values: a) are based on 2008 estimates, un-indexed for intervening cost changes; b) reflect a 10% discount from Mr. Pasteris's 2008 estimates; and c) reflect a further significant discount resulting from differing assumptions as to the levelization method used in the financial model.[11] Mr. Pasteris's new "bottom-up" estimate fully assesses the costs to build a new CC plant in the PJM region in 2010, superceding his prior (2008) estimate and mooting the 10% discount to the 2008 value.

2. Change in Levelization Method.

PJM also is eliminating the levelization difference, which had the effect of reducing both the CC and CT estimates in the MOPR by approximately 15%. The CONE CT estimate used in the VRR Curve is based on a "nominal levelized" financial model, which assumes that O&M expenses increase by 2.5% per year and calculates the single fixed annual revenue requirement that has the same present value as the increasing revenue requirements over twenty years that reflect those increasing operating expenses. The current MOPR CC and CT values, by contrast, are based on the first-year revenue requirement of a "real levelized" model, which also assumes a 2.5% annual increase in operating expenses, but which assumes that plant revenue requirements will increase each year to reflect those increased expenses. The real levelized approach produces a lower number in the early years of the project's life than the nominal levelized approach, and a higher number in the later years.

PJM's April 2009 compliance filing rationalized the use of the lower, real levelized first-year value in the MOPR on the theory that a plant developer might legitimately choose to present its costs in either way, since they both produce the same present value.[12] PJM no longer agrees, however, that this downward adjustment should be accepted automatically as reasonable, which is the effect of the current rule that embeds that adjustment in the MOPR screen. First, PJM notes that the MOPR-type provisions the Commission has approved for the NYISO and ISO-NE tariffs do not include any levelization differences or other project costing methodology differences that are designed to produce a lower estimate for the MOPR screen than the CONE estimate otherwise used in their capacity models.[13]

---

12 *See* April 2009 Compliance Filing at 4, n. 14 & 15.

13 As discussed below, both of these ISOs set the screen based on a percentage level applied to the CONE estimate. But they do not reduce the cost estimate and then also apply a percentage factor to further reduce the screen, which is the approach taken by PJM's current MOPR.

Whether new entry power plants are financed by corporate debt and equity or by project financing, the asset must be expected to generate a reasonably predictable revenue stream to support the investment and repay debt. Lenders will seek assurance that the rate structure can recover all of the project's costs over the term of the loan. Thus, practically speaking, a project with revenues that will recover only its first-year level of costs will not be financed. Generally speaking, lenders will look for a power-sales agreement that recovers increasing annual costs either through an automatic escalation clause or a fixed annual, i.e., nominal levelized, revenue requirement. If a project's power sales agreement and financing are based on a nominal levelized approach, then offering the plant into RPM at only a real levelized first-year price would be in effect offering below the project's claimed costs. But even if otherwise consistent with the project's agreements, an RPM bidding strategy that assumes the project will be able to claim a higher price in future years, after it is no longer a new entry unit, would be subject to question. Generally speaking, a new-entry unit will have the greatest leverage in an RPM auction, and therefore can command the highest price, when its entire investment is avoidable, i.e., before the plant is built and its costs become sunk. A seller legitimately concerned with recovering its project's costs over time through RPM therefore would be expected to offer its plant at the highest permissible first-year price, i.e., that produced by the nominal levelized approach.

This is not to say that such a bidding strategy is *never* appropriate. But the current MOPR screen incorrectly assumes it is *always* appropriate, and thus provides a possible avenue for uncompetitively low offers. Therefore, PJM is removing this assumption from the MOPR screen. The supplied gross CONE reference values for both CC and CT plants are based on the nominal levelized method, and language in the existing rule that references a "real levelized (year one)" approach is being deleted.

3. Construction Cost Index Adjustment.

The current MOPR provision states gross CONE values for a CC plant and a CT plant but makes no provision for tracking changes in construction costs from year to year. The gross CONE estimate for a CT plant used in the VRR Curve, by contrast, includes a Commission-approved indexing provision. For that estimate, the Commission has approved use of an automatic adjustment based on changes in applicable construction-cost indices, known as the Handy-Whitman Index, that are widely used in the utility industry.[14] The same approach can help ensure that the MOPR screens remain up-to-date without the need for a new "bottom-up" estimate (and a new FPA section 205 filing) every year. PJM therefore proposes to use for the MOPR gross CONE values the same method used for the VRR Curve gross CONE value. For the VRR Curve, the Tariff states the applicable Handy-Whitman index as that for "Other Production Plant." Under the Handy-Whitman method of categorizing costs, that index is intended to apply to any combustion-turbine based plant, which would include combined-cycle plants that incorporate CTs, as is common in the PJM region. PJM therefore proposes to use the same index for both the CT and CC estimates in the MOPR screen as is used today for the VRR Curve CT CONE estimate.

---

14 *March 2009 Order* at PP 63-65.

As with the VRR Curve CONE value, this automatic adjustment method is expressly without prejudice to PJM filing a fully supported section 205 change to the MOPR values at any time. In that regard, PJM notes that it is required to review the VRR Curve parameters, including the gross CONE estimate, every three years, and (following a stakeholder process) file any appropriate changes to those parameters with the Commission under section 205. The next triennial review required by the Tariff is in 2011. If the CT value is changed as a result of that process, PJM will also file to change the MOPR CT value; PJM could efficiently review the MOPR CC values through that same process.

4. Energy and Ancillary Services Revenue Offset.

The current MOPR provision states that the Net Asset Class CONE is "net of energy and ancillary service revenues."[15] However, the current MOPR refers to the stated dollar reference values (which as shown above were justified to the Commission as gross CONE figures) as "Net" Asset Class CONE values, and never explains how the energy and ancillary service revenues will be determined. PJM is resolving these ambiguities by amending the MOPR to refer to the updated dollar values as the gross CONE component of the Net Asset Class CONE determination, and by specifying how the energy and ancillary services ("EAS") revenue offset will be calculated. For this purpose, PJM is adopting the same method already approved to calculate the EAS revenue estimate for the net CONE used in the VRR Curve.

For the VRR Curve's EAS offset estimate, PJM calculates the energy revenues that the presumed new entry CT plant would have earned had it been in service in PJM for the three most recent full calendar years, given the locational marginal prices and fuel prices in effect during those three years. The estimate is based on the CT plant's Tariff-specified heat rate and variable O&M expenses and a stated "Peak-Hour Dispatch" unit dispatch scenario. PJM then uses the annual average over those three years as the plant's expected energy revenues, and lastly adds a stated annual revenue value for the reactive services the plant would be expected to supply.

PJM is revising the MOPR to make clear that the net CONE for a CT in the MOPR screen will use exactly the same EAS revenue offset estimate as is used for the CT net CONE in the VRR Curve. The same basic method also will be used for the CC net CONE screen in the MOPR, but certain elements of that calculation now stated in the Tariff are appropriate for a CT but not for a CC. PJM therefore is adding to the MOPR differing values for a heat rate, variable O&M expense, and ancillary services revenue, that are appropriate for a CC. Each of these revised factors is appropriate. The adopted heat rate is customary for a CC plant; Mr. Pasteris supports the variable O&M expense for a CC plant; and the ancillary service revenue estimate is the MW-weighted cost of providing reactive service from a CC plant, based on reactive service cost filings filed with the Commission under Schedule 2 to the PJM Tariff. PJM also is clarifying that the dispatch assumption to estimate CC energy revenues is slightly different than that used for CT energy revenues: although the CT is assumed to be dispatched only for the

[15] Tariff, Attachment DD, section 5.14(h)(1) ("MOPR").

four-hour blocks that it is economic, the CC is expected to be dispatched for nearly all of the daytime hours on the days when it is economic.

5. Locational Differences.

As explained above, PJM is proposing for the MOPR screen several different gross CONE values, varying by location within the PJM Region, tracking the VRR Curve's use of different CONE values by "CONE Area." This locational variability recognizes not only locational differences in capital costs but also locational differences in the energy revenues a new plant can expect to receive. Under PJM's locational marginal price ("LMP") energy market, generator revenues can vary substantially from place to place within the PJM Region. For the Net CONE in the VRR Curve, PJM associates the gross CONE in a CONE Area (which may encompass multiple transmission owner zones) with the energy revenues calculated for a zone within that area. Specifically, PJM's Tariff provides that the energy revenue estimate will be calculated for the zone in which the gross CONE estimate assumed the new power plant would be built.[16]

PJM proposes this same approach for the EAS estimate used in the MOPR screen calculations, with one adjustment. Instead of basing the energy revenue estimate on the zone where the generic "Reference Resource" is assumed to be built, PJM will base it on the zone within each CONE Area that has the highest energy revenue estimate. This approach ensures that the sell offer of a new entrant will not fail the MOPR screen merely because it is located in a zone with higher LMPs than the zone in which the hypothetical reference resource was assumed to be built. This change also increases the confidence that a sell offer significantly below the reference value is suspect, and should not be accepted unless the seller can demonstrate, through the exception process described below, that its offer is appropriate.

For the convenience of the Commission and the parties, PJM has calculated the Net Asset Class CONEs for both a CC plant and a CT plant, taking all of the above MOPR revisions, into account, fo ruse in the May 2011 auction. Those values are set forth in Attachment D to this filing.

B. Percentage Factor Applied to Reference Value to Determine MOPR Screen

Once the net CONE value is determined for the particular resource type, the MOPR applies a percentage factor to that reference value to determine the screen level, i.e., theTariff-specified lower bound on the reasonableness of a new entry offer. For a CC or CT, the current MOPR sets that level at 80% of the Net Asset Class CONE for those resource types. For any other, unspecified plant type (that is not expressly allowed to submit a zero-price offer, as discussed below), the screen is set at a default level of 70% of the Net CONE for a CT.

No Commission order has discussed the rationale for the percentage factor in PJM's MOPR, or for the similar factors used for the NYISO and ISO-NE MOPR-type rules. Nor was

16 Tariff, Attachment DD, section 5.10(a)(v).

this factor explained or justified in the materials submitted with the 2006 RPM settlement. In PJM's view, such a factor is best viewed simply as a recognition that the RTO's administrative Net CONE estimate is merely an estimate, and a particular unit's actual costs could vary from that estimate. Viewed in this context, there is no single percentage factor that is definitively superior. Rather, the factor selected is a matter of judgment, based on a balance of competing interests.

On the one hand, setting the screen at the same level as the Net CONE reference value (i.e., using a percentage factor of 100%) implies that PJM's Net Asset Class CONE estimate is presumptively correct, and any departure below that value, no matter how small, is suspect. This approach could have the effect of increasing the number of new entry offers each year that run afoul of the MOPR and must pursue the exception process described below, increasing administrative burdens and transaction costs for such resources. This approach, however, decreases the likelihood that an improper sell offer can evade the MOPR.

On the other hand, using a relatively lower percentage factor (such as the current MOPR's 80%) shows greater tolerance for possibly legitimate variations in costs or expected revenues below PJM's administrative estimates, and therefore will likely subject fewer sellers to the burden of justifying their offers. However, that approach increases the risk that a seller can evade the MOPR and use a below-cost price to suppress clearing prices for all sellers. Indeed, this approach could invite sellers to attempt to suppress the price by a substantial amount (20% in this example) without fear of triggering the MOPR.

Taking these competing factors into consideration, PJM proposes to retain a percentage factor (i.e., set the MOPR screen level *below* PJM's estimate of Net Asset Class CONE), but set that screen (for a CC or CT) at 90%. A screen of 90% sets a reasonable balance between legitimate competing interests: on the one hand, recognizing the imprecision of "one-size fits all" administrative estimates, balanced against, on the other hand, preserving protections against an unreasonable exercise of market power.

Retention of a percentage factor appropriately recognizes that PJM's administrative estimate is not perfect. The costs of a specific new resource may, and almost certainly will, vary from PJM's estimate, and a seller should not be forced to justify its offer to the Commission based merely on a minor variance from PJM's estimate.

However, that factor is too low at its current level of 80%. If PJM's estimate is in fact a reliable indication of the cost of new entry, then an 80% factor would permit a seller to suppress prices as much as 20% below the competitive level. The harm to market integrity that could result from application of the current 80% factor cannot be justified in favor of allowing variation from bright line, administrative cost estimates—particularly when (as detailed below) PJM proposes other options for capacity market sellers to seek and obtain relief from application of the MOPR.

A 90% factor strikes the right balance between competing interests. Moreover, the 90% factor is supported by the detail and variation already included in the Net CONE reference value as PJM is proposing it. PJM has developed separate estimates for a CC plant and a CT plant (unlike NYISO and ISO-NE, which use only the CT Net CONE). Within each plant type, PJM also has separate estimates for different sub-regions within PJM, and conservatively bases the energy revenue estimate for each CONE Area in the zone with the highest energy revenues. This conservative assumption will tend to reduce the Net Asset Class CONE reference value. In addition, PJM's gross CONE estimates are highly detailed and well-supported, as can be seen from the report accompanying Mr. Pasteris's affidavit. Lastly, PJM will now use the Handy-Whitman Index to assure that the MOPR reference values keep pace with changes in construction costs (up or down) from year to year, and will review the detailed, bottom-up, estimates at least every three years, in association with the triennial review already provided in the Tariff for review of Net CONE.

Moreover, tolerating a ten percent downward variance from estimated costs also is consistent with the Commission's long-standing acceptance of ten percent adders to costs as just and reasonable. The Commission has "traditionally" approved ten percent adders "on the grounds that the ten percent adders recover incidental, miscellaneous expenses that are expensive or difficult to quantify."[17] Indeed, this principle is embedded in RPM's offer cap calculations, which permit a ten percent adder to costs.[18] Using the long-accepted ten percent value to define a permissible downward variance from PJM's administrative estimate of the Net Asset Class CONE therefore provides an appropriate and symmetrical means of recognizing that estimating uncertainties can cause costs to vary on the downside, as well as to the upside. In a similar vein, the Commission accepted a ten percent reduction to a PJM estimate as being within the zone of reasonableness.[19]

For all of these reasons, PJM proposes to set the MOPR screens for a CC and CT plant at 90% of PJM's estimate of the Net Asset Class Cone for each of those resources. PJM also is retaining the default screen for any other, unspecified plant technologies of 70% of the Net CONE for a CT. PJM views that figure as a placeholder that is unlikely to be invoked. Generator development lead times are such that if a need for a new asset class estimate is identified in the future, there should be adequate time to develop and add such an estimate to the Tariff.

---

17 *Terra Comfort Corporation*, 52 FERC ¶ 61,241, at 61,840 (1990).

18 Tariff, Attachment DD, section 6.8(a) (adjustment factor of 1.10 "provide[s] a margin of error for understatement of costs").

19 *March 2009 Order* at PP 26, 38.

C. Process for Obtaining Approval of Sell Offers that Violate the MOPR Screen.

1. Requirement for Commission Determination.

The MOPR currently provides that an offer that fails the MOPR's screens need not be mitigated if the seller "obtains a determination from FERC" that its offer is consistent with the project's costs and with expected revenues from other PJM markets.[20] However, the MOPR does not specify any procedure for obtaining that determination.

The MOPR's current approach is consistent with the Commission's repeated holdings that neither PJM nor its market monitor are permitted to make discretionary, unilateral decisions whether capacity sale offers are either too high or too low to be competitive. In 2009, for example, the Commission rejected a proposal to replace the current MOPR with a provision that would have given responsibility to the Independent Market Monitor ("IMM") to determine, based on certain Tariff-defined standards, whether a seller's new entry offer was an exercise of market power. The Commission found no justification for providing the IMM with "unfettered discretion to determine whether an offer violates the MOPR."[21] The Commission emphasized that PJM "must provide objective tariff provisions that will determine when mitigation measures will be applied, including application of the MOPR rule," so as to "provide needed certainty to all participants."[22]

Similarly, in its order on the 2006 RPM settlement, the Commission rejected aspects of the MOPR as originally drafted by the settling parties that allowed the market monitor to determine if new entry offers were uncompetitively low (as well as a corresponding provision that enlisted the market monitor to determine if new entry offers were uncompetitively high).[23] As the Commission explained, such discretion is inappropriate because it would have allowed the market monitor "to use its sole judgment to determine inputs that can ultimately set the market clearing price."[24]

Accordingly, when a sell offer is submitted that falls outside the bounds permitted by the MOPR, PJM proposes neither itself nor the IMM as the arbiter of whether an exception to the MOPR's bright-line rule is warranted. Rather, and in recognition of the rate setting nature of the matter, PJM is retaining the current MOPR procedure that the seller must obtain a determination from the Commission that the offer is justified and an exception is appropriate. However, as the

---

20 MOPR, section 5.14(h)(3).

21 *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 190 (2009).

22 *Id.*

23 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at PP 114-15 & n.81 (2006).

24 *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 180 (2007).

current rule does not specify how that determination is to be obtained, PJM is revising the MOPR to clarify that the filing to the Commission will be pursuant to FPA section 206. This is consistent with the Commission's directive to the NYISO to adopt an exception process via section 206, as discussed below. This also is implicit in the current MOPR's reference to sellers obtaining determinations from the Commission on the acceptability of their offers. In effect, the seller would be seeking to show that, *as applied* to its specific costs and its specific revenue expectations, the MOPR screen is unjust and unreasonable.[25]

This process need not be burdensome. PJM receives relatively few sell offers in the RPM base auctions each year that are based on new combined cycle or combustion turbine power plants.[26] And very few of those would be expected to submit offers significantly below the net cost of new entry each year. Notably, the PJM Region has had a process in place for many years by which generation providers file with the Commission their costs of providing reactive service under Schedule 2 of the PJM Tariff, and the necessary determinations have routinely been implemented on a timely basis under that process. Indeed, in many cases, since the MOPR screen is only a screen, capacity market sellers may offer a perfectly adequate explanation why their new entry offer is significantly below the Net Asset Class Cost of New Entry. A seller's specific project may legitimately have lower fixed costs, or higher reasonable revenue expectations (or a combination of both) relative to PJM's generic determination of the net costs for the particular asset class. In such circumstances, PJM would have no objection to advising the Commission, through written, on-the-record comments, of PJM's views on the seller's offered justification, and PJM presumes that the IMM would do so as well. Thus, the occasional case-specific exceptions to the bright-line MOPR test on acceptable sell offers would be resolved in a transparent fashion that promotes confidence in the integrity of the RPM auctions.

2. Exception Based on State Mandate.

As a related change, PJM proposes to retain an exception for offers that are justified on state policy grounds, but to place it under the same process as any other sell offer seeking a MOPR exception, i.e., an FPA section 206 filing with the Commission. The current MOPR has an exception for new entry sell offers based on a resource "that is being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall," so long as that determination is made in a state evidentiary proceeding "that includes due notice, PJM

---

25 Under the circumstances presented here, and consistent with the *NYISO* precedent, it appears that FPA section 206 is the appropriate vehicle for the validation of a sell offer that is otherwise contrary to an approved Tariff provision. Nonetheless, PJM does not purport to preclude any party from seeking any form of relief it may properly seek and that it considers appropriate to its circumstances, including a request for declaratory order, for example.

26 For all RPM Delivery Years addressed in Base Residual Auctions to date (except the 2011-2012 Delivery Year) there were seven or fewer such offers each year. For the 2011-12 Delivery Year, there were thirteen.

participation and an opportunity to be heard."[27] As currently drafted, therefore, this provision puts PJM (as Tariff administrator) in the position of having to pass on the adequacy of state administrative processes as part of determining whether to accept a sell offer that might otherwise fail the MOPR screens. PJM also would have to determine, in the first instance, whether an offer was legitimately intended to address a projected capacity shortfall in the relevant area.

The sufficiency of state policy justifications is a matter much better addressed to the Commission. Indeed, the Commission recognized as much when it directed the NYISO to add to its MOPR-type provision a rule that parties seeking to justify a new entry offer on state policy grounds must submit an FPA section 206 filing to the Commission to obtain that relief. In the NYISO proceeding, the New York Public Service Commission ("NYPSC") argued that the MOPR-type provision would interfere with the state commission's "standards for resource adequacy and the ability to self-supply ICAP," including public policy preferences for new resources that promote fuel diversity or advance environmental objectives.[28] In response, the Commission found that the state's proposed changes to the provision "would lead to artificially depressed capacity prices, thus both causing existing generators to be under-compensated and also directly and adversely impacting the Commission's ability to set just and reasonable rates for capacity sales in the in-City market."[29] On rehearing, the Commission re-affirmed its view that deference to a state's interest in resource adequacy does not trump the Commission's responsibility to assure just and reasonable rates,[30] but recognized that the NYPSC might conclude that procurement of new capacity, even when RTO market signals indicate no new capacity is needed, may further certain specific state policy objectives. The Commission therefore announced that the NYPSC "may make a filing under section 206 of the FPA to justify a mitigation exemption for entry of new capacity that is required by a state-mandated requirement that furthers a specific legitimate state objective."[31]

The same approach should apply here. As the Commission held when it rejected a challenge to the MOPR's current exception on this issue, it is reasonable to acknowledge the possible legitimacy of "reliability projects built under state mandate," because they "enable[] states to meet their responsibilities to ensure local reliability."[32] However, such projects can have adverse price effects that run counter to the Commission's purpose in approving RPM and similar capacity programs. Therefore, whether to allow capacity sell offers from such projects if

---

27 MOPR at section 5.14(h)(1)(iv)(allowing a zero sell offer in such circumstances).

28 *New York Independent System Operator, Inc.*, 122 FERC ¶ 61,211, at P 92 (2008).

29 *Id.* at P 110.

30 *New York Independent System Operator, Inc.*, 124 FERC ¶ 61,301, at PP 35-36 (2008).

31 *Id.* at P 38.

32 *Id.*

they fail the MOPR screen can present difficult issues and likely would involve a balancing of competing policy interests. Such determinations go well beyond the limited role of a tariff administrator and are properly the province of the Commission. Accordingly, PJM is replacing the current, purportedly self-implementing, exception process for state-mandated reliability projects with an exception process, like that approved for the NYISO, that necessarily involves the Commission, through an FPA section 206 filing.

PJM adopts language from the *NYISO* orders to capture the principles that will govern any such exception request. Specifically, PJM has drafted the exception language to focus the parties on new entry that is pursuant to "a state-mandated requirement that furthers a specific legitimate state objective" and that the Sell Offer would not "lead to artificially depressed capacity prices" or "directly and adversely impact [the Commission's] ability to set just and reasonable rates for capacity sales" in the PJM Region or any affected Locational Deliverability Area.[33]

D. Elimination of "Net Short" Criterion

The current MOPR provides that it applies only to a capacity market seller and its affiliates that have a substantial "net short position" in the relevant RPM auction, i.e., the seller and its affiliates are effectively buying substantially more capacity from the auction than they are selling into it.[34] This provision is intended to focus the MOPR on parties that have an incentive to use a low-price offer for a (presumably marginal) new entrant to reduce the clearing price that the seller (in its role as buyer) will pay for capacity committed in the auction. However, this pre-condition on application of the MOPR opens considerable opportunities for a seller/buyer with exactly that incentive to structure the new entry transaction in way that achieves the desired price-lowering effects without triggering the MOPR's protective provisions. For example, a buyer wishing to reduce the clearing price below a competitive level for the benefit of its loads could achieve that result through the terms of its power purchase agreement with the new entrant, even though the buyer is neither the seller nor an affiliate of the seller. Such a buyer could simply commit to cover the seller's costs, and direct in the contract that the seller offer the new plant's capacity at a low price (or even at a zero price). Thus, the current "net short" provision renders the MOPR too easily gamed, and may create such obvious pathways for evading the MOPR that the rule in its current form might never be applied.

The Commission recognized this same concern with a MOPR-type rule in the tariff of the New York Independent System Operator, Inc. ("NYISO"), and responded by holding that there should be no "net buyer" condition in that MOPR provision. In its initial order on the NYISO's MOPR-type provision, the Commission noted that while the intent was to address net buyers, NYISO's proposal applied to all sellers in the New York City market. The Commission found this inappropriate, observing that "[n]ew capacity offered by net sellers of capacity would not . . .

33 *See* revised MOPR at section 5.14(h)(5).

34 MOPR at section 5.14(h)(3)(iii).

enter the ICAP market with uneconomic capacity" but would only enter "when the market sends the price signal indicating that profit can be earned by entering the market."[35] The Commission therefore directed the NYISO to revise its tariff to make clear that the mitigation rule applies only to net buyers. On rehearing, however, the Commission reversed itself, finding that "*all* uneconomic entry has the effect of depressing prices below the competitive level and . . . this is the key element that mitigation of uneconomic entry should address."[36] Moreover, the Commission agreed with the NYISO and others that sought rehearing that "defining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures."[37]

PJM's "net short" provision is essentially the same as the "net buyer" rule that the Commission held should not be a pre-condition to application of a MOPR-type rule. Consistent with the Commission's NYISO precedent, and because the "net short" provision opens substantial opportunities to game and evade the MOPR, the "net short" pre-condition is properly deleted.

E. Elimination of Impact Test

Under the current MOPR, a sell offer failing the screens is subject to mitigation only if it would reduce the auction clearing price by 20 to 30 percent (depending on the size of the LDA) compared to the clearing price that would result if the offer is mitigated (i.e., raised to a competitive level). If the current rule's impact test is not met, then a new entry sell offer is allowed to go forward, just as if there was no MOPR provision in the PJM Tariff, even if the offer is well below the MOPR screen level and the seller has provided no justification for a below-cost offer.

There is no similar impact test under either the NYISO or ISO-NE MOPR-type provisions requiring a percentage change in the clearing price before a non-competitive offer is mitigated. Indeed, the Commission moved toward elimination of hurdles or preconditions to the operation of the similar buyer-side mitigation rules in these RTOs. In addition to eliminating the "net buyer" precondition to the NYISO MOPR-type rule, the Commission has targeted for closer scrutiny provisions of ISO-NE's version of a MOPR (known as the Alternative Price Rule or APR) that set conditions on triggering the APR that are unduly complex.[38] In that regard, the Commission has observed that a new entry resource that is supported by out-of-market revenues "can suppress the market clearing price even when no new capacity is needed," by displacing an

---

35 *Id.* at P 106.

36 *New York Independent System Operator, Inc.*, 124 FERC ¶ 61,301, at P 29 (2008) (emphasis added).

37 *Id.*

38 *Id.* at P 76.

existing resource that would have been marginal and set the clearing price—if not for the below-cost offer from the resource that relies on out-of-market payments.[39] For both of these other RTOs, the Commission has made clear that the MOPR-type rule "should be triggered when a buyer is in a position to exercise market power."[40]

Nor does PJM interpose an impact test before it mitigates other types of sell offers that are found non-competitive. When conditions indicate that a seller is in a position to exercise market power, whether that seller has a new plant or an existing plant, then mitigation is applied, without first assessing how severely the exercise of market power will affect the clearing price.[41] Symmetry, and equivalent treatment of uncompetitively high offers and uncompetitively low offers, dictates that the same rule should apply here. Even a small change in the clearing price from a below-cost offer can harm competition if it deters entry, or spurs retirement, of a resource that would have been competitive, had the MOPR seller offered at its true costs.

Accordingly, PJM is deleting from the MOPR existing subsection (3), which sets forth the sensitivity analysis and 20-30% impact test. Indeed, rather than awaiting the auction results to determine whether to mitigate an offer that fails the MOPR screen, PJM will simply mitigate such offers in advance of the auction, just as PJM regularly determines before the auction whether other types of offers will be subject to mitigation. If an offer fails the MPR screens, then the seller's offer will be "set equal to" the MOPR screen level (i.e., 90% of the Net Asset Class CONE), just as the offers of existing resources that exceed the applicable offer price ceiling are "set equal to" that ceiling price.[42]

Given this change, PJM is making two other conforming changes. First, PJM is deleting the existing criterion that MOPR applies only to a sell offer that "affects" the clearing price.[43] Given the elimination of the impact test, retention of a requirement that the MOPR offer "affect" the clearing price would be confusing and ambiguous. As discussed above, offers that fail that MOPR screen will be mitigated regardless of their effect on the auction clearing price. PJM notes, however, that it is not eliminating the current provision that the MOPR applies only in Locational Deliverability Areas for which PJM has established a separate VRR Curve (thus indicating that the LDA either is constrained or close to being constrained.

Second, PJM is deleting existing subsection (4) of the MOPR. That subsection prescribes rules for PJM to re-order the supply curve after it conducts the sensitivity test, re-sets the price

39 *Id.*

40 *Id.* at P 75.

41 *See, e.g.*, Tariff, Attachment DD, section 6.5(a)(i) (mitigation measure for existing resources), 6.5(a)(ii) (mitigation measure for new resources).

42 *See* Tariff, Attachment DD, section 6.5(a)(i).

43 MOPR, section 5.14(h)(3)(i).

level of the MOPR offer, and calculates an alternative clearing price and total cleared supply quantity. Because PJM is eliminating the sensitivity test and the parallel alternative calculation of the clearing results, this procedure for constructing an alternative supply stack is moot. As explained above, PJM will set the MOPR offer equal to the screen level in advance of the auction, and the MOPR offer will clear (or not clear) in accordance with that price level.

F. Application of MOPR to Various Resource Types

By its current terms, the MOPR broadly applies to Planned Generation Capacity Resources, i.e., sell offers based on new generation capacity, but then specifies various generator types that are not required to offer at a price higher than zero.[44] The list of generator types is not complete, however, raising questions as to whether and how the MOPR applies to certain plant types, and the current rule is ambiguous and inconsistent in other respects as well. PJM now proposes to resolve these omissions and ambiguities.

PJM proposes to keep the existing rule's tolerance of a zero-price offer for nuclear, coal and Integrated Gasification Combined Cycle facilities. The only change PJM is making to this provision is to drop its references to "base load" resources and facilities "that require a period of development greater than three years." These descriptive phrases add little to the list of technology types, and invite debate over the meaning of terms such as "base load." PJM also is keeping the current rule's tolerance of zero price for hydroelectric resources, and is adding wind and solar facilities to that category. The net cost of these intermittent resources will bear little relation to the Net Asset Class estimates that will be determined under the Tariff for CC and CT plants, and may be complicated by credits and incentives with laudatory public policy objectives having nothing to do with capacity price suppression. Under current circumstances, it seems more likely that a market participant with an objective to suppress prices would pursue that objective through a resource, such as a combined cycle or combustion turbine, that is more likely to be a marginal resource in the RPM auctions. Thus, attempting to develop a minimum, cost-based resource price for renewable resources is probably beyond the point of diminishing returns.

PJM proposes to eliminate, however, the zero-price exception for "any upgrade or addition to an Existing Capacity Resource." Such a resource is a planned resource if it adds capacity, and adding capacity to an existing CC or CT plant could well be an effective means of pursuing a price-suppression strategy. If such an offer falls below the applicable MOPR screen, then the offer should be allowed only if it goes through the justification process described below.

G. Time Period for MOPR Application

The current MOPR applies to new entry offers only in the first year that a resource qualifies as a planned resource. The Commission has recognized, however, for both the NYISO

---

44 MOPR, section 5.14(h)(1).

and ISO-NE, that a new resource seeking to suppress price could do so for a number of years after it enters the market.[45]

Consistent with this precedent, PJM is revising the MOPR to apply to a new entrant for a total of three years, beginning with the first RPM Base Residual Auction the planned resource clears. The three-year term appropriately matches the three-year lag between the time a Planned Generation Resource first clears a BRA, and the time the Planned Generation Capacity Resource would enter commercial operation for the first delivery year for which the Planned Generation Resource is committed. In the interim, there will be two additional BRAs in which the Planned Generation Capacity Resource would presumably offer, but not yet be in commercial service and still have considerable avoidable project investment and development costs in the event the Planned Generation Capacity Resource did not clear in the subsequent two BRAs. For example, consider a Planned Generation Capacity Resource that offers into the 2014/2015 BRA in May 2011 for the first time expecting to be in-service three years later, i.e., just prior to the 2014/2015 Delivery Year. If the Planned Generation Capacity Resource clears the 2014/2015 BRA, the resource is still considered "planned" when the 2015/2016 and 2016/2017 BRAs are held in May 2012 and May 2013, respectively, since it is likely not yet in-service at the time of those two subsequent BRAs. In short, the three-year period matches the time during which the costs of the new resource are not fully sunk, giving practical recognition to the seller's ability to affect the clearing prices during that period.

PJM commences this three-year term with the first year the resource clears, rather than the first year it is offered in the auction, to preempt a strategy in which a resource tries to evade the MOPR by offering in its first year a price that it knows is unlikely to clear.

H. Clarification that Self-Supply Is Subject to the MOPR

PJM has never intended to exempt self-supply offers from application of the MOPR. However, one subsection of the current MOPR refers to self-supply, and that subsection is admittedly ambiguous. Perhaps as a result, the P3 Complaint expresses a great deal of concern that the current MOPR exempts self-supply. PJM therefore proposes clarifying changes on this point.

Current subsection (4) of the MOPR refers to self-supply in the context of the construction of a revised supply curve after the MOPR is triggered and one or more new entry sell offers are re-priced to a higher level. As discussed above, PJM is deleting this subsection in its entirety, as PJM will no longer conduct a post-auction sensitivity analysis or construct an alternative supply curve. Accordingly, PJM's Tariff changes eliminate the reference to self-supply in the MOPR. To further eliminate any doubt, PJM is adding a cross-reference to the

---

45 *New York Independent System Operator, Inc.*, 122 FERC ¶ 61,211, at PP 114-116 (2008); *ISO-New England*, 131 FERC ¶ 61,065, at P 83 (2010).

RPM Tariff section that generally addresses self-supply, to clarify that any self-supply offers are subject to the MOPR.[46]

I. Elimination of Sunsetting Rule

The current MOPR contains an automatic sunsetting provision. According to its terms, the MOPR will terminate when there is a positive net demand for new resources over a period of consecutive years beginning with the first RPM Delivery Year, in a specified portion of the PJM Region that was not capacity-constrained at the time RPM was implemented.[47] The provision relies upon a definition of "net demand for new resources" from a separate RPM tariff rule that was deleted in 2009.

PJM proposes to delete this provision. Aside from the provision's reliance on a sunsetting test that has been deleted, the objectives served by the MOPR are not time-limited. The Commission has repeatedly found that uneconomic entry could be used to depress clearing prices and has repeatedly found it just and reasonable to adopt provisions that protect against such uneconomic entry.[48] Accordingly, the MOPR should not be subject to automatic termination, no more than any other RPM protections against uneconomic conduct by sellers should be subject to automatic termination.

J. Date Certain to Propose NEPA Changes

While PJM updates and corrects various aspects of the MOPR, in part to address possible issues concerning out-of-market support for new entry, PJM agrees with the view express in some quarters that additional support is needed to encourage new entry. PJM continues to receive comments from new entry project developers, representatives of the investment community, and proponents of state support for new entry, that new entry requires greater revenue certainty from competitive wholesale markets than the market rules currently provide. Rather than rely on out-of-market mechanisms that are available only to a handful of select resources, the better approach would be to enhance PJM's rules for in-market revenue assurances.

---

46 *See* Tariff, Attachment DD, section 5.2.

47 MOPR section 5.14(h)(5).

48 *See, e.g., PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 191 (2009); *ISO-New England, Inc.*, 131 FERC ¶ 61,065, at P 75 (2010) (MOPR-type rule "should be triggered when a buyer is in a position to exercise market power"); *New York Independent System Operator, Inc.*, 122 FERC ¶ 61,211, at P 100 (2008) (MOPR-type rule accepted to "prevent uneconomic entry that would reduce prices in the NYC capacity market below just and reasonable levels").

RPM's New Entry Price Adjustment ("NEPA") currently provides a new entry project, in certain narrow circumstances, assurance that it will receive its "new entry" price, i.e., the clearing price from the first year the new plant decides to enter a constrained LDA, for two additional years.[49] PJM sought to modify this provision in 2009, by easing some of the pre-conditions on availability of the NEPA and by extending the period of revenue assurances to five or seven years. The Commission concluded, however, that it could not accept those changes, finding that they would result in "price discrimination between existing resources, including demand response, and new generation suppliers" and did not strike the right balance between facilitating project financing and minimizing uplift payments from loads.[50]

PJM is committed to seeking solutions in this area to address both the possible need for greater revenue assurance and the Commission's concerns with possible undue discrimination. PJM recognizes, however, that it may be difficult to achieve a stakeholder consensus on these points, given the controversy resulting from past efforts to reform the NEPA rules. To help advance a solution, PJM asks the Commission to approve the enclosed Tariff change that sets a deadline of October 1, 2011 for PJM to file, following a stakeholder process, any NEPA reforms that can satisfy the twin objectives of supporting new entry while avoiding undue discrimination between new and existing units.

K. Interconnection Process Reforms

Beyond RPM, other PJM market rules can affect the pace of new entry, and PJM is committed to ensuring that those rules remain just and reasonable. For example, PJM devotes considerable effort and resources to its generator interconnection process so as to treat all interconnection customers fairly while not burdening the process with undue delay. Although the current queue rules are just and reasonable and conform to Commission policy, there may be opportunities for greater efficiencies in this area, and for distinguishing between interconnection requests based on progress, objectively measured, towards the ultimate goal of delivering new capacity to serve the reliability needs of the PJM Region. PJM intends to lead its stakeholders this year in a review of possible queue reforms that can both advance reliability and reduce uncertainty and delays for project developers, and file any resulting Tariff changes with the Commission by the end of this year.

---

49 Tariff, Attachment DD, section 5.14(c).

50 *March 2009 Order* at P 149.

III. Correspondence

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W, Suite 600
Washington, D.C. 20005
(202) 423-4743
glazec@pjm.com

Barry S. Spector
Paul M. Flynn
Wright & Talisman, P.C.
1200 G. Street, N.W., Suite 600
Washington, D.C., 20005
(202) 393-1200
spector@wrightlaw.com
flynn@wrightlaw.com

Vincent P. Duane
Vice President & General Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403-2497
(610) 666-4367
duanev@pjm.com

IV. Description of Submittal

Along with this transmittal letter, PJM submits electronic versions of the revisions to the Tariff in both clean and marked forms (as Attachments A and B, respectively),[51] the affidavit and supporting materials of Mr. Pasteris, as described above (as Attachment C), a chart showing the estimated MOPR screens for use in the upcoming Base Residual Auction (as Attachment D), and a PDF-format copy of this entire filing.

---

51 Language in the affected Tariff sections that is pending Commission approval is shown in italics.

V. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[52] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[53] alerting them that this filing has been made by PJM today and is available by following such link.

VI. Conclusion

Accordingly, PJM respectfully requests that the Commission accept the enclosed Tariff revisions, effective April 13, 2011.

Respectfully submitted,

/s/ Paul M. Flynn

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W, Suite 600
Washington, D.C. 20005
(202) 423-4743
glazec@pjm.com

Barry S. Spector
Paul M. Flynn
Wright & Talisman, P.C.
1200 G. Street, N.W., Suite 600
Washington, D.C., 20005
(202) 393-1200
spector@wrightlaw.com
flynn@wrightlaw.com

Vincent P. Duane
Vice President & General Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403-2497
(610) 666-4367
duanev@pjm.com

---

52 *See* 18C.F.R §§ 35.2(e) and 385.2010(f)(3).

53 PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected commissions.

Attachment A
Clean Tariff Sheets

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction *or an Incremental Auction* in accordance with the procedure and time schedule set forth in the PJM Manuals. *The* LSE shall indicate its intent in the Sell Offer *that the Capacity Resource be deemed Self-Supply and shall indicate whether it is* commit*ting* the resource regardless of clearing price *or with a price bid*. Any such Sell Offer shall be subject to the minimum offer price rule set forth in section 5.14(h). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and*, if the LSE indicated that it is committing the resource regardless of clearing price*, will treat such Capacity Resource as committed in the clearing process of the *Reliability Pricing Model* Auction for *which it was offered for* such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as *not Self-Supply* (to the extent not so required) *and subject to an offer price*, in accordance with the PJM Manuals. *PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.*

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, (2) the Locational Price Adder, if any in such LDA, (3) the Annual Resource Price Adder, if any, and (4) the Extended Summer Resource Price Adder, if any, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

2. Acceptance of such Sell Offer in such BRA increases the total Unforced Capacity in the LDA in which such Resource will be located from a megawatt quantity below the

LDA Reliability Requirement to a megawatt quantity corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

3. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource; or B) 0.90 times the then-current Net CONE, on an Unforced Capacity basis, for such LDA.

If the Sell Offer is submitted consistent with the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all resources in the LDA receive the Capacity Resource Clearing Price.

(ii) in the subsequent two BRAs, if the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA. If the Resource does not clear, it shall be deemed resubmitted at the highest price per MW at which the Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and it shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer that is entitled to compensation for such first year pursuant to section 5.14(b) of this Attachment. The Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect such resubmission. In such case, the Resource submitted under this provision shall be paid for the entire committed quantity the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer Price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2.

For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

4) On or before October 1, 2011, PJM shall file with FERC under FPA section 205 revisions to this section 5.14(c) as determined necessary by PJM following a stakeholder process, to address concerns expressed by some parties that this provision in its current form may not provide adequate long-term revenue assurances to support new entry. Any such changes also shall honor concerns expressed by FERC and others that any such revisions must not lead to undue price discrimination between existing and new resources.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. *PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.*

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. *PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.*

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located;

and 4) an adjustment, if required, to account for Resource Make-Whole Payments, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); and (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to

determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, 2014, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT") and a combined cycle generator ("CC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	138,646	128,226	131,681	128,226	128,340
CC $/MW-yr	175,250	154,870	164,375	154,870	154,870

(2) Beginning with the Delivery Year that begins on June 1, 2015, the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.980 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.

(4) Any Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, or submitted in any Base Residual Auction up to and including the second successive Base Residual Auction after the Base Residual Auction in which such resource first clears, in any LDA for which a separate VRR Curve has been established, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry

for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from FERC described in subsection (5) hereof

(5) A Sell Offer meeting the criteria in subsection (4) shall be permitted if the Capacity Market Seller submits to FERC a filing under section 206 of the Federal Power Act sufficiently in advance of the Base Residual Auction to obtain a determination from FERC, and in fact obtains a determination from FERC prior to such auction, that such Sell Offer is permissible because it is either (A) consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets, and the resource received no out-of-market payments); or (B) the Sell Offer is based on new entry that is pursuant to a state-mandated requirement that furthers a specific legitimate state objective and that the Sell Offer would not lead to artificially depressed capacity prices or directly and adversely impact FERC's ability to set just and reasonable rates for capacity sales in the PJM Region or any affected Locational Deliverability Area.

(i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

Attachment B
Redlined Tariff Sheets

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction *or an Incremental Auction* in accordance with the procedure and time schedule set forth in the PJM Manuals. *The* LSE shall indicate its intent in the Sell Offer *that the Capacity Resource be deemed Self-Supply and shall indicate whether it is* commit*ting* the resource regardless of clearing price *or with a price bid*. Any such Sell Offer shall be subject to the minimum offer price rule set forth in section 5.14(h). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and*, if the LSE indicated that it is committing the resource regardless of clearing price*, will treat such Capacity Resource as committed in the clearing process of the *Reliability Pricing Model* Auction for *which it was offered for* such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as *not Self-Supply* (to the extent not so required) *and subject to an offer price*, in accordance with the PJM Manuals. *PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.*

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, (2) the Locational Price Adder, if any in such LDA, (3) the Annual Resource Price Adder, if any, and (4) the Extended Summer Resource Price Adder, if any, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

~~a~~1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

~~b~~2. Acceptance of such Sell Offer in such BRA increases the total Unforced Capacity in the LDA in which such Resource will be located from a megawatt quantity below the

LDA Reliability Requirement to a megawatt quantity corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

~~c~~3. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource equal to the lesser of: ~~1~~A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource; or ~~2~~B) 0.90 times the then-current Net CONE, on an Unforced Capacity basis, for such LDA.

If the Sell Offer is submitted consistent with the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all resources in the LDA receive the Capacity Resource Clearing Price.

(ii) in the subsequent two BRAs, if the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA. If the Resource does not clear, it shall be deemed resubmitted at the highest price per MW at which the Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and it shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer that is entitled to compensation for such first year pursuant to section 5.14(b) of this Attachment. The Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect such resubmission. In such case, the Resource submitted under this provision shall be paid for the entire committed quantity the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer Price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2.

For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

4) On or before October 1, 2011, PJM shall file with FERC under FPA section 205 revisions to this section 5.14(c) as determined necessary by PJM following a stakeholder process, to address concerns expressed by some parties that this provision in its current form may not provide adequate long-term revenue assurances to support new entry. Any such changes also shall honor concerns expressed by FERC and others that any such revisions must not lead to undue price discrimination between existing and new resources.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. *PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.*

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. *PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.*

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located;

and 4) an adjustment, if required, to account for Resource Make-Whole Payments, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); and (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based~~, real~~ nominal levelized ~~(year one)~~ Cost of New Entry, net of energy and ancillary service revenues. ~~Other than the levelization approach, d~~Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New

Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. ~~Until changed, t~~The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, 2014, the values indicated in the table below for each CONE Area for a combustion turbine generator (“CT”)~~shall be $ 96,485MW-year,~~ and ~~the Net Asset Class Cost of New Entry for~~ a combined cycle generator (“CC”), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. ~~shall be $ 117,035/MW-year.~~ Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based ~~load resources, such as~~ on nuclear, coal ~~and~~ or Integrated Gasification Combined Cycle facilities~~, that require a period for development greater than three years~~; or (ii) Sell Offers based on~~any facility associated with the production of~~ hydroelectric, wind, or solar facilities~~ power; (iii) any upgrade or addition to an Existing Generation Capacity Resource; or (iv) any Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard~~.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	138,646	128,226	131,681	128,226	128,340
CC $/MW-yr	175,250	154,870	164,375	154,870	154,870

(2) Beginning with the Delivery Year that begins on June 1, 2015, the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.980 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.

(~~2~~4) Any Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, or submitted in any Base Residual Auction up to and including the second successive Base Residual Auction after the Base Residual Auction in which such resource first clears, in any LDA for which a separate VRR Curve has been established, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above ~~meets each of the following criteria,~~ shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure)~~subject to the provisions of subsection (3) hereof~~, unless the Capacity Market Seller obtains the prior~~a~~ determination from FERC described in subsection (5) hereof~~prior to such Base Residual Auction that such Sell Offer is consistent with the real levelized (year one) competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets):~~

~~i. Sell Offer affects the Clearing Price;~~

~~ii. Sell Offer is less than 80 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as stated in subsection (h)(1) above; and~~

~~iii. The Capacity Market Seller and any Affiliates has or have a "net short position" in such Base Residual Auction for such LDA that equals or exceeds (a) ten percent of the LDA Reliability Requirement, if less than 10,000 megawatts, or (b) five percent of the total LDA Reliability Requirement, if equal to or greater than 10,000 megawatts. A "net short position" shall be calculated as the actual retail load obligation minus the portfolio of supply. An "actual retail load obligation" shall mean the LSE's combined load served in the LDA at or around the time of the Base Residual Auction adjusted to account for load growth up to the Delivery Year, using the Forecast Pool Requirement. A "portfolio of supply" shall mean the Generation Capacity Resources (on an unforced capacity basis) owned by the Capacity Market Seller and any Affiliates at the time of the Base Residual Auction plus or minus any generation that is, at the time of the BRA, under contract for the Delivery Year.~~

(5) A Sell Offer meeting the criteria in subsection (4) shall be permitted if the Capacity Market Seller submits to FERC a filing under section 206 of the Federal Power Act sufficiently in advance of the Base Residual Auction to obtain a determination from FERC, and in fact obtains a determination from FERC prior to such auction, that such Sell Offer is permissible because it is either (A) consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets,

and the resource received no out-of-market payments); or (B) the Sell Offer is based on new entry that is pursuant to a state-mandated requirement that furthers a specific legitimate state objective and that the Sell Offer would not lead to artificially depressed capacity prices or directly and adversely impact FERC's ability to set just and reasonable rates for capacity sales in the PJM Region or any affected Locational Deliverability Area.

~~(3) The Office of the Interconnection shall perform a sensitivity analysis on any Base Residual Auction that included Sell Offers meeting the criteria of Section 5.14(h)(2), for which the Capacity Market Seller has not obtained a prior favorable determination from FERC as described in subsection (2) hereof. Such analysis shall re-calculate the clearing price for the Base Residual Auction employing in place of each actual Sell Offer meeting the criteria a substitute Sell Offer equal to 90 percent of the applicable estimated cost determined in accordance with Section 5.14(h)(1) above, or, if there is no applicable estimated cost, equal to 80 percent of the then-applicable Net CONE. If the resulting difference in price between the new clearing price and the initial clearing price differs by an amount greater than the greater of 20 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 15,000 megawatts; or the greater of 25 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 5,000 and less than 15,000 megawatts; or the greater of 30 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement of less than 5,000 megawatts; then the Office of the interconnection shall discard the results of the Base Residual Auction and determine a replacement clearing price and the identity of the accepted Capacity Resources using the procedure set forth in section 5.14(h)(4) below.~~

~~(4) Including all of the Sell Offers in a single Base Residual Auction that meet the criteria of 5.14(h)(3) above, PJM shall first calculate the replacement clearing price and the total quantity of Capacity Resources needed for the LDA. PJM shall then accept Sell Offers to provide Capacity Resources in accordance with the following priority and criteria for allocation: (i) first, all Sell Offers in their entirety designated as self-supply *committed regardless of price*; (ii) then, all Sell Offers of zero, prorating to the extent necessary, and (iii) then all remaining Sell Offers in order of the lowest price, subject to the optimization principles set forth in Section 5.14.~~

~~(5) Notwithstanding the foregoing, this provision shall terminate when there exists a positive net demand for new resources, as defined in Section 5.10(a)(iv)(B) of this Attachment, calculated over a period of consecutive Delivery Years beginning with the first Delivery Year for which this Attachment is effective and concluding with the last Delivery Year preceding such calculation, in an area comprised of the Unconstrained LDA Group (as defined in section 6.3) in existence during such first Delivery Year. Notwithstanding the foregoing, the Office of the Interconnection shall reinstate the provisions of this section, solely under conditions in which a constrained LDA has a gross Cost of New Entry equal to or greater than 150 percent of the greatest prevailing gross Cost of New Entry in any adjacent LDA.~~

(i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

Attachment C
Affidavit of Raymond M. Pasteris
and Supporting Report on
the Cost of New Entry
by a Combined Cycle Power Plant

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER11-___-000**
	)	

AFFIDAVIT OF RAYMOND M. PASTERIS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

My name is Raymond M. Pasteris, and I am the President of Pasteris Energy, Inc. ("Pasteris Energy"). I am submitting this affidavit in support of the proposal by PJM Interconnection, L.L.C. ("PJM") to update the estimated fixed costs to build and operate a new combined cycle ("CC") power plant in the PJM region. The CC power plant revenue requirements, expressed in $/MW-Year or $/MW-Day, are based on the total project capital cost and annual fixed operations and maintenance ("O&M") expenses of a new combined cycle power plant. I prepared separate cost estimates for three PJM subregions: CONE Area 1/AECO (New Jersey), CONE Area 2 PEPCO (Maryland) and CONE Area 3/COMED (Illinois).

The results of my analysis are set forth in the attached report, "Independent Study to Determine Cost of New Entry Combined Cycle Power Plant Revenue Requirements For PJM Interconnection, LLC.," which was prepared under my direction and supervision. My qualifications and experience are set forth in Addendum 3 of the attached report. Pasteris Energy retained Stantec Consulting Services, Inc. ("Stantec"), an engineering and consulting firm with power plant project design and cost estimating experience, to develop the plant proper capital cost estimates.

Pasteris Energy also retained Wood Group Power Operations, Inc. ("WGPO") to provide assistance in determining plant startup, staffing, and expenses, capitalized spare parts, O&M staffing, and annual fixed maintenance expenses. WGPO provides contracted operations and maintenance services to the power industry primarily with combustion turbine-based power plants. Pasteris Energy also retained the Air Resources Group, LLC of Albany, New York to assist in determining emissions reduction credits requirements of the CONE CC power plant.

The fixed-cost estimate and resulting fixed revenue requirements are based on a 600 MW two-on-one GE Frame 7FA combined cycle power plant, which is a typical design configuration for combined cycle plants in the PJM region.

The resulting estimated annual revenue requirements (levelized over twenty years) for the CC power plant are $175,250/MW-Year for a CONE Area 1/AECO (New

Jersey) site; $154,870/MW-Year for a CONE Area 2/PEPCO (Maryland) site and $164,375/MW-Year for a CONE 3/COMED (Illinois) site.

I also estimated the variable operations and maintenance ("VOM") expenses likely to be incurred by the CC plant configuration. I understand that PJM will use this VOM estimate in connection with its estimate of the net energy and ancillary service revenues likely to be earned in the PJM market by the CC plant configuration. I estimated the CC plant 2010 VOM at $3.228/MWh. This is based on my 2008 VOM estimate of 2.800/MWh, which was derived from manufacturers and power plant owner estimates, and escalated to 2010 using the Handy-Whitman index.

Revenue requirements are presented in $/MW-Year and $/MW-Day and are total levelized. The total levelized value represents constant, non-escalating annual capacity revenues over the 20-year project life beginning in 2010 having the same NPV as the 20-year revenue requirements escalating at 2.5% starting in 2010.

Any differences in revenue requirements between the three sites are primarily a result of construction labor and O&M labor rates and productivity, land costs, property taxes and state income tax rates. Details on the methodology used to determine the CONE CC capital cost and fixed revenue requirements in current 2010 dollars are found in the attached report.

This concludes my affidavit.

	)	State of Pennsylvania
SS:	)	
	)	City of Yardley

AFFIDAVIT OF RAYMOND M. PASTERIS

Raymond M. Pasteris, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Raymond M. Pasteris on Behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Raymond M. Pasteris

Raymond M. Pasteris

Subscribed and sworn to before me this 3rd day of February, 2011.

NOTARIAL SEAL
Jerry McKenna
NOTARY PUBLIC
Twp of Northampton, Bucks County
My Commission Expires 09/21/2014

/s/

Notary Public

My Commission expires: 9-21-2014

1

Cost of New Entry Combined Cycle Power Plant Revenue Requirements

For

PJM Interconnection, LLC.

Pasteris Energy, Inc.
430 Trend Road
Yardley, PA 19067
Tel. 215-736-8170
Fax. 215-736-8171

February 3, 2011

TABLE OF CONTENTS

TABLE OF CONTENTS (CON'T)

TABLE OF TABLES

Executive Summary

Introduction

In August of 2004 PJM retained Pasteris Energy, Inc. ("Pasteris Energy") to determine the cost of a new entry ("CONE") generation technology and its resulting fixed revenue requirements expressed in $/MW-Year or $/MW-Day as part of the PJM RPM process. The results of that study were issued on August 30, 2005 and were used to determine the upper price boundary of the capacity price demand curve for the four RPM transitional auctions for capacity years 2007-2008, 2008-2009, 2009-2010 and 2010-2011.

In 2008 Pasteris Energy was again retained by PJM to determine the fixed revenue requirements for a nominal 600 MW combined cycle ("CONE CC") power plant. Though the capital cost of a combined cycle power plant exceeds that of the current CONE CT power plant, the lower combined cycle power plant heat rate could yield lower revenue requirements after accounting for net energy revenues ("net CONE") than the CONE CT configuration. Accordingly PJM requested that combined cycle technology be evaluated.

PJM has now retained Pasteris Energy to update the CONE CC revenue requirements to a mid-year July 1, 2010 convention.

The CONE revenue requirements are based on the total project capital cost and annual fixed operations and maintenance ("O&M") expenses of a combined cycle ("CC") power plant addition within three geographic locations of PJM encompassing the following regions. CONE Area 1 comprising the PS, JCP&L, AE, PECO, DPL and RECO zones, CONE Area 2 comprising the BGE and PEPCO zones and CONE Area 3 comprising the AEP, APS, ATSI, Dayton, DEOK, Duquesne and ComEd zones. This study has selected sites in New Jersey-EMAAC, Maryland-SWMAAC and Illinois-RTO, respectively. This evaluation only considers capital and fixed O&M costs. Net revenues from the sale of energy and ancillary services are not included in this report.

Evaluation Methodology

In 2008 Stantec Consulting Services, Inc. ("Stantec") formerly Industry and Energy Associates, Inc., ("IEA") a power plant design and engineering firm with CT and CC plant experience was contracted by Pasteris Energy to determine the plant proper capital cost estimates for the 600 MW GE Frame 7FA combined cycle power plant. Stantec assembled these estimates based upon recent major equipment "Power Island" costs obtained from Stantec's recent participation with power plant developers, and balance of plant equipment quotations. The power plant construction estimate was developed based on data from recent EPC proposals and input obtained from multiple construction contractors. For this effort, the three labor rates and labor productivity for the three geographical locations of New Jersey, Maryland and Illinois were verified and used to develop the direct and indirect costs. The plant proper estimate is an engineering, procurement and construction ("EPC") turnkey cost estimate in current July 1, 2008 dollars. For this 2010 update Stantec applied the same cost estimating methodology described above to cost estimate the New Jersey location only. To update the capital cost for the Maryland and Illinois locations the 2008 cost estimates for Maryland and New Jersey where line by line adjusted based by the 2010 to 2008 ratio of the same line items of the 2010 and 2008 New Jersey cost estimate. Handy Whitman indices were not used.

The Wood Group Power Operations, Inc. ("WGPO") provided assistance in determining plant startup staffing and expenses, capitalized spare parts, O&M staffing, and annual maintenance expenses. WGPO provides contracted operations and maintenance services to the power industry primarily with combustion turbine based power plants. WGPO updated their 2008 cost estimates to 2010.

Pasteris Energy determined and updated other development expenses such as property purchase, environmental permitting, legal, project management and interest during construction. Pasteris Energy utilized PJM's capital cost database to estimate electric interconnection and system upgrade costs. Pasteris Energy determined the annual property tax payments and plant insurance premiums.

Proforma Analysis

A twenty (20) year after tax discounted cash flow ("ATDCF") model was used to determine the fixed levelized revenue requirements for the CONE CC project to cover capital recovery, annual fixed O&M expenses and earn the target after tax internal rate of return ("IRR") for the investor/owner. The mid-year convention was used to account for revenues and fixed expenses incurred continuously throughout each year in the 20 year project evaluation. This methodology for evaluating power generation investments is the most commonly used by power plant owners and developers. Accordingly, the financial results of this study will be consistent with the financial results obtained by owners and developers when applying the study capital costs, annual O&M expenses and financial criteria. The model only accounts for the capital costs to develop and construct the plant and annual fixed O&M expenses. It includes, fixed capacity revenue, fixed O&M expense, debt service, depreciation, income taxes and after tax cash flow. Variable operating expenses such as fuel and variable operations and maintenance ("VOM") expenses were not included in the financial model. Theses variable expenses are accounted for in the PJM net energy and ancillary services net revenue calculations made by PJM for determining net CONE.

Financial Criteria

Target Internal Rate of Return ("IRR")

A target IRR of 12% was chosen for the proforma evaluation and is based on achieving this IRR in year 20 of the project life. This target IRR has been used in all previous CONE studies.

Debt to Equity Ratio

A 50% debt to 50% equity ratio was assumed in the proforma model evaluation. This ratio is consistent with the financial structure of a creditworthy integrated electric utility company or independent power company ("IPP"). This would be a reasonable financial structure for the CONE CC plant project and has been used in all previous CONE studies.

Debt Term and Interest Rate

Consistent with the financial structure of a creditworthy integrated electric utility company or IPP a long term, 20-year, bond with an interest rate of 7.0 % was used in the proforma model. A mortgage style loan was used which provides for increasing principal payment and decreasing interest payments over the loan term. This financial structure has been used in all previous CONE studies.

Tax Depreciation

The federal tax code allows for combined cycle power plants to utilize Modified Accelerated Cost Recovery System (“MACRS”) over a 20 year tax life for combined cycle plants on the qualifying portions of the total project cost. Please note that a simple cycle power plant is allowed 15 year MACRS depreciation.

<u>Federal and State Corporate Income Tax Rates</u>

A 35.0% federal income tax rate was used in the proforma model. The state tax rate for New Jersey was 9.0 %, Maryland, 8.25% and Illinois 7.3%.

<u>Escalation</u>

An annual escalation rate of 2.5% was assumed for all fixed O&M expenses over the entire project life. This is consistent with all previous CONE studies.

CONE CC Capital Cost Revenue Requirement Results

The resulting capital cost and fixed revenue requirements for the CONE CC power plants for the New Jersey, Maryland and Illinois plant sites are found on Table 1. The values are presented in 2008 and 2010 dollars. Revenue requirements are presented in $/MW-Year and $/MW-Day and are total levelized. The total levelized value represents constant, non-escalating annual capacity revenues over the 20-year project life beginning in 2008 and 2010 having the same NPV as the 20-year revenue requirements escalating at 2.5% starting in 2008 and 2010, respectively.

Any differences in revenue requirements are primarily a result of construction labor and O&M labor rates and productivity, land costs, property taxes and state income tax rates. Details on the methodology used to determine the CONE CC capital cost and fixed revenue requirements in current 2008 dollars and current 2010 dollars are found in the details of this report.

TABLE 1

CONE COMBINED CYCLE CAPITAL COST AND REVENUE REQUIREMENTS

CONE CC Capital Costs in July 2008 Dollars		
Geographic Location Within PJM	$Million	$/kW
CONE Area 1 [1]	$679.657	$1,131.1
CONE Area 2 [2]	$592.846	$986.6
CONE Area 3 [3]	$653.075	$1,086.8

20 Year Nominal Levelized Revenue Requirements						
Geographic Location Within PJM	CONE Area 1 [1]		CONE Area 2 [2]		CONE Area 3 [3]	
Levelized Revenue Requirements	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year
Capital	$411.56	$150,218	$357.93	$130,646	$391.93	$143,054
Fixed O&M	$57.93	$21,143	$58.85	$21,482	$52.78	$19,266
Total	$469.48	$171,361	$416.79	$152,128	$444.71	$162,320

CONE CC Capital Costs in July 2010 Dollars		
Geographic Location Within PJM	$Million	$/kW
EMAAC [1]	$693.591	$1,154.25
SWMAAC [2]	$603.567	$1,004.44
RTO [3]	$661.455	$1,100.77

20 Year Nominal Levelized Revenue Requirements						
Geographic Location Within PJM	CONE Area 1 [1]		CONE Area 2 [2]		CONE Area 3 [3]	
Levelized Revenue Requirements	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year
Capital	$420.73	$153,565	$365.15	$133,279	$396.96	$144,892
Fixed O&M	$59.41	$21,685	$59.15	$21,591	$53.38	$19,483
Total	$480.14	$175,250	$424.30	$154,870	$450.34	$164,375

Plant Description	
CT Model	GE Frame 7FA
Number of CTs	2
Number of HRSGs	2
Number of STGs	1
Unfired Plant Capacity (MW at 92 F)	479.6
Unfired Heat Rate (BTU/kWh) (HHV)	6,979
Fired Plant Capacity (MW at 92 F)	600.9
Fired Heat Rate (BTU/kWh) (HHV)	7,315
Financial Assumptions	
Percent Equity	50%
Percent Debt	50%
Debt Term (Years)	20
Project Life (Years)	20
Debt Interest Rate (%)	7.0%
Target Equity IRR (%)	12.0%
General Escalation (%)	2.5%
MARCS Depreciation (Yrs)	20

[1] CONE Area 1 encompasses the PS, JCP&L, AE, PECO, DPL and RECO zones.
[2] CONE Area 2 encompasses the BGE and PEPCO zones.
[3] CONE Area 3 encompasses the AEP, APS, ATSI, Dayton, DEOK, Duquesne and ComEd zones.

1.0 CONE Combined Cycle Plant Design
1.1 GE Frame 7FA Combined Cycle Plant

Since its introduction to the markets approximately twenty years ago the GE Frame 7FA has been a technically and commercially successful combustion turbine in simple and combined cycle operation. The particular Frame 7FA model used in this study is the PG7241. Many of these specific units have been installed in the PJM system in simple and combined cycle configuration. There are greater then thirty GE Frame 7FA units currently installed and operating in the PJM region many in combined cycle power plants.

The Frame 7FA CC power plant design is similar and consistent with the majority of new CC power plants constructed in PJM having two or more GE Frame 7FA units. The nominal out put of the CT at 59 °F is 168 MW. This plant is a three-pressure; reheat cycle with two CT/HRSG trains feeding a single steam turbine generator (“STG”). The hot CT exhaust gases flow into a three pressure level steam reheat HRSG with duct burner firing capability. The STG contains a high pressure (“HP”) section, intermediate pressure (“IP”) section and low pressure (“LP”) to condensing section on one shaft connected to a nominal 320 MW electric generator. At maximum duct burner firing HP steam is generated at 1,850 PSIG and 1,050 °F and throttled to the HP steam turbine section. Steam exits the HP turbine at approximately 600 PSIG; 735 °F and is reheated in the HRSG to 1,020 °F. This reheated steam combines with additional IP steam generated by the HRSG and enters the IP steam turbine. Steam exits the IP turbine at 85 PSIG and combines with LP steam generated by the HRSG and enters the LP turbine to condensing in a surface condenser. Heat is rejected via a ten cell mechanical draft wet cooling tower. The primary fuel is natural gas with distillate kerosene oil as liquid fuel backup. It is assumed that pipeline natural gas is available at adequate pressure to be utilized by the CT without on site fuel gas compression. The minimum fuel gas pressure requirement of the GE Frame 7FA is 450 PSIG. HRSG duct burners have been included to increase the unfired CC net capacity an additional 120 MW.

The Frame 7FA, when firing natural gas, utilizes dry low NOx (“DLN”) combustor technology to reduce nitrous oxide (“NOx”) emissions to 9.0 PPM at 15% O_2. Carbon monoxide (“CO”) emissions from the CT are also 9.0 PPM at 15% O_2. Selective Catalytic Reduction (“SCR”) technology has been installed in the HRSG to further reduce NOx emissions to 2.0 PPM at 15% O_2. Oxidation catalyst has also been installed in the HRSG to reduce CO emissions to 2.0 PPM at 15% O_2. Assuming two CT units both operating 8,760 hours annually with duct burner in service the NOx potential to emit is approximately 228 tons per year. This total includes NOx emitted during plant operation, startup and shutdown. While firing distillate kerosene, water injection is used to reduce NOx emissions from the CT to 42 PPM. At this NOx level entering the SCR achieving a stack NOx level of 2.0 PPM would not be expected. Accordingly, the plant may be limited to a specified, not to exceed annual operating hours on distillate kerosene. While in the unfired duct burner operation the total plant emits 27.57 Lbs/Hr of NOx. When operating in the maximum duct burner firing mode the NOx emissions increase to 45.88 Lbs/Hr.

The unit is not designed with black start capability. Because of the large mass of the rotating elements the Frame 7FA windings in the electric generator are used to start the unit. Smaller CT units typically use an external motor driven hydraulic system for startup. Though technically feasible it is deemed not cost effective to consider black start for the CONE CC in order to obtain black start revenues. Accordingly, no black start ancillary service revenues are available from the CONE CC power plant.

Evaporative turbine inlet air-cooling ("TIC") is included in the Frame 7FA CC plant design. The efficiency of the evaporative cooling is assumed to be 85% which brings the inlet air to within 85% of saturation or the corresponding ambient wet bulb temperature. Evaporative cooling is not used below 75 F dry bulb temperatures in our performance modeling.

2.0 Construction Scope and Capital Cost

2.1 Plant Proper Capital Cost

Stantec Consulting Services, Inc. ("Stantec") formerly Industry and Energy Associates, Inc., ("IEA") a power plant design and engineering firm with CT and CC plant experience was contracted by Pasteris Energy to determine the plant proper capital cost estimates for the 600 MW GE Frame 7FA combined cycle power plant. Stantec assembled these estimates based upon recent major equipment "Power Island" costs obtained from Stantec's recent participation with power plant developers, and balance of plant equipment quotations. The power plant construction estimate was developed based on data from recent EPC proposals and input obtained from multiple construction contractors. For this effort, the labor rates and labor productivity for the three geographical locations of New Jersey, Maryland and Illinois were verified and used to develop the direct and indirect costs. The plant proper estimate is an engineering, procurement and construction ("EPC") turnkey cost estimate in current July 1, 2008 dollars and current July 1, 2010 dollars.

Plant Proper Escalation Assumptions

For this 2010 update Stantec applied the same methodology described above to cost estimate the New Jersey location only. To update the capital cost for the Maryland and Illinois locations the 2008 and 2010 cost estimates for the New Jersey location were line by line indexed and were applied to the same line items as the 2008 Maryland and Illinois locations.

The 2008 CONE CC plant proper cost for New Jersey plant site was estimated by Stantec at $544.524 Million, for Maryland plant site at $469.367 Million and for Illinois plant site at $524.505 Million. The 2010 CONE CC plant proper cost for New Jersey plant site was estimated by Stantec at $555.637 Million. Indexing the New Jersey plant proper cost to the Maryland plant site provided a cost of $477.558 Million and for the Illinois plant site $534.784 Million.

2.2 Construction and Draw Down Schedules

Stantec also provided construction and draw down schedules. The construction schedule from site mobilization to commercial operation is 24 months. The cost draw down schedule however extends over a 42 month period accounting for a Limited Notice to

Proceed ("LNTP") in month one, a release of the Power Island purchase in month four, due to the 30-month delivery of the steam turbine generator, and the balance of plant procurement from months ten through eighteen. Site mobilization occurs in month nineteen of the overall schedule. Stantic provided the percent of total plant proper capital cost at each of the 42 months in the schedule and was used by Pasteris Energy to determine interest during construction ("IDC"). Due to the long delivery time for the steam turbine generator and the fact that obtaining air permits could take 14 to 24 months, a combined cycle power plant would already need to be in its 12th to 18th month of development at the time of this report to achieve commercial operation by June 1, 2014.

2.3 Black Start Capability

Black start capability is not included in the Frame 7FA CC plant as the GE Frame 7FA CT is not started via a separate motor driven hydraulic system but utilizes the generator winding as a motor to start the unit using electric from the system. The required installed oil fired diesel generator capacity exceeds 12.0 MW to start a single Frame 7FA CT and supply adequate power to the combined cycle plant auxiliaries. Though black start is feasible for a 600 MW CC power plant it is deemed to be not cost effective.

2.4 Duel Fuel Capability

The GE Frame 7FA CT is capable of natural gas and distillate kerosene oil operation and the necessary equipment including on site fuel oil storage has been included in the CC plant proper capital cost.

3.0 Other Project Capital Costs

3.1 Electric Interconnection

In the normal course of power project development the PJM Transmission Planning Department manages the capital costs for power plant direct interconnection to the PJM system as well as the cost of PJM system upgrades. For the CONE CC evaluation, 272 power plant interconnection and system upgrade costs were available in the database for proposed, in construction and recently completed power projects. Project installed capacities ranged from 1 MW to 1,642 MW. The database was sorted into a 500 MW to 830 MW capacity range that represented the range of the CONE CC project under evaluation.

In 2008 this capacity range produced 19 projects with an average direct interconnection cost of $11.27 per kW and $8.65 per kW for PJM system upgrades. This produced a total interconnection and system upgrade cost of $19.92 per kW of installed net plant capacity. This value was increased by $2.00 per kW to a value of $21.92 per kW net plant capacity to include power lines from the CONE CC power plant to the PJM interconnection point.

In 2010 this capacity range produced 21 projects with an average direct interconnection cost of $9.21 per kW and $6.93 per kW for PJM system upgrades. This produced a total interconnection and system upgrade cost of $16.13 per kW of installed net plant capacity. This value was increased by $2.09 per kW to a value of $18.22 per kW net plant capacity to include power lines from the CONE CC power plant to the PJM interconnection point.

The $2.00 per kW power line cost was escalated using the Handy Whitman index for Total Electric Transmission Plant Line 33 of E-1.

3.2 Natural Gas Interconnection

PJM does not compile a database of natural gas interconnection costs. The pipeline distance from the plant to the high-pressure gas interconnection point is assumed to be five (5) miles for this cost estimate. The CONE CC evaluation assumes that natural gas is available at a pressure level adequate to be used directly in the CT without on site fuel gas compression. For the CONE CC plant this pressure is assumed to be 450 PSIG. The 2008 capital cost for the HP natural gas pipeline was estimated at $1.0 Million per mile. The cost estimate for the natural gas metering station at the plant site is $1.0 Million resulting in a total capital cost of $6.0 Million. This yields a cost of $9.98 per net kW capacity to represent the total cost of natural gas interconnection including the metering station and a gas pipeline outside the plant proper.

To adjust the cost of the natural gas interconnection to 2010 the Handy-Whitman Index for gas transmission construction was used. The index from 2008 to 2010 was 0.907 and resulted in a cost of $8.66 per net kW.

3.3 Plant Mobilization and Startup Costs

As a power plant nears construction completion the owner begins to mobilize for the commissioning, performance testing and startup of the power plant. These costs are typically capitalized and include hiring, relocation expenses, labor costs of the O&M staff nine (9) month before startup, training, production of O&M manuals, special tools and office equipment and furnishings. Startup consumables were also capitalized which include purchased electricity, fuel, water and chemicals consumed during plant commissioning and performance testing.

WGPO provided the mobilizations costs for the CONE CC power plant. WGPO provides startup, operations and maintenance services for CT based power plants. The 2008 mobilization cost for the CONE CC power plant was estimated at $4,671,882.

Fuel, water and electric costs were assumed to include 72 hours of CT full load testing and 3,600 hours or five (5) months of plant parasitic electric load purchased from the local utility. Credit was taken for electric revenues during plant testing. The consumable expenses for the Frame 7FA CT plant were estimated by Pasteris Energy to be $258,400. The total plant mobilization and startup costs are $4,930,282. WGPO updated theses costs to $4,981,365 for 2010.

3.4 Initial Capitalized Spare Parts Inventory

WGPO estimated the spare parts inventory consistent with their estimate for startup and O&M services provided to the CONE CC power plants. The capitalized spare parts for the CONE CC plant were estimated at $2,793,750 in 2008.

To determine the 2010 cost of capitalized spare parts the Handy-Whitman Index for gas turbo-generators was used. It was assumed the combustion turbine spare parts would be procured with the Power Island. Accordingly, two years of escalation was applied increasing the spare parts cost to $3,220,382.

3.5 Project Development Costs

Internal and contracted expenses for professional services can be capitalized. These costs include, development, legal, financial and technical professionals during the development, construction and startup of the project. Pasteris Energy, having experience in power project development, estimated these costs. The development costs for the CONE CC power plant is estimated at $9,759,000. Historical CPI escalation was used for two years, July 2008 to July 2010, increasing the development cost to $9,883,785.

Environmental and regulatory professional services and application fees to obtain air, land use and FERC permits were estimated at $765,000 for the CONE CC plant. Pasteris Energy retained the Air Resources Group, LLC (“ARG”) of Albany, New York to assist in determining this development cost. ARG updated these cost for 2010 at $1,040,000.

3.6 Land Costs

The 2008 cost of property for siting the CONE CT plant was obtained by contacting real estate agencies in south New Jersey, Maryland and northern Illinois. The 2008 average cost for the New Jersey plant site property was $150,000 per acre, for the Maryland plant site property, $135,000 per acre and for the Illinois plant site property, $109,200 per acre. For the CONE CT update in 2010 plant industrial property cost trends and graphs for each area were used showing reductions in property costs. Accordingly, these reductions were applied yielding for the New Jersey plant site property, $130,208 per acre, for the Maryland plant site property, $121,060 per acre and for the Illinois plant site property, $92,613 per acre.

Stantec provided a plot plan for the CONE CC plant. The plant proper foot print for the power plant was approximately 25 acres.

3.7 Interest During Construction

Interest during construction (“IDC”) was determined based on the construction costs and monthly draw down schedules provided by IEA. An interest rate of 5.0% on the outstanding debt was utilized for the calculation of IDC. The short term nature of this loan usually results in a lower interest rate than the term loan which is 7.0 %. Due to the extended 42 month schedule and the need to place down payments on the Power Island in month four of the schedule IDC has become a significant expense or about 7.5% of the total project capital cost.

3.8 Owner’s Contingency

In the CONE CC power plant evaluation an owner’s contingency was added to the total project capital cost of 2.5% of the plant proper EPC cost or about 2.1% of the total project capital cost. This is consistent with all previous CONE studies.

3.9 Emissions Reduction Credits

Pasteris Energy retained the Air Resources Group, LLC of Albany, New York to assist in determining ERC requirements of the CONE CC power plant.

For each of the regions for the siting of the CONE CC the purchase of emissions offsets are required. These are known as emissions reduction credits ("ERC"). The cost of the ERC for a particular pollutant is the product of the annual expected emissions in tons per year and the cost per ton of that pollutant and the emissions offset factor. The following Table 2 details the determination of the ERCs for the three CONE area sites.

TABLE 2
EMISSIONS REDUCTION CREDITS

Year	2010		
CONE Area	Area 1	Area 2	Area 3
Pollutant	Tons/Yr	Tons/Yr	Tons/Yr
NOx	244.9	244.9	244.9
PM 2.5	134.4	134.4	134.4
VOC	41.1	41.1	41.1
SO2	176.6	176.6	176.6
CAIR	244.9	244.9	244.9
RGGI CO2	2,215,507	2,215,507	2,215,508
Pollutant	Price $/Ton	Price $/Ton	Price $/Ton
NOx	$8,000	$8,000	$2,000
PM 2.5	$8,000	$8,000	$0
VOC	$2,000	$2,000	$1,500
SO2	$200	$200	$200
CAIR	$300	$300	$300
RGGI CO2	$1.86	$1.86	$0.00
Pollutant	Offset Factor	Offset Factor	Offset Factor
NOx	1.3	1.3	1.3
PM 2.5	1.0	1.0	1.0
VOC	1.3	1.3	1.3
SO2	1.0	1.0	1.0
CAIR	1.0	1.0	1.0
RGGI CO2	1.0	1.0	1.0
Pollutant	ERC Cost ($000)	ERC Cost ($000)	ERC Cost ($000)
NOx	$2,547.0	$2,547.0	$636.7
PM 2.5	$1,075.2	$1,075.2	$0.0
VOC	$106.9	$106.9	$80.1
SO2	$35.3	$35.3	$35.3
CAIR	$73.5	$73.5	$73.5
RGGI CO2	$4,120.8	$4,120.8	$0.0
2010 Total	$7,958.7	$7,958.7	$825.7
2008 Total	$3,232.0	$3,232.0	$727.8

The CONE CC power plant will need NOx budget allowances under the CAIR program. It is assumed that no new source set aside allowances will be available thus the plant will be required to tap the auction market for its initial year allowances. Thus, these costs would also be capitalized.

Details of the CONE CC power plant design, scope, capital costs, construction schedule, and plant drawings provided by Stantec may be found in the attached Addendum No. 1. The capital cost buildup for the CONE CC power plant may be found on Table 3 below.

TABLE 3

PJM CONE CC POWER PLANT

GE FRAME 7FA TWO ON ONE CONFIGURATION

CAPITAL COST DETAIL BY PJM GEOGRAPHIC LOCATION

PJM REGION	CONE Area 1[1]		CONE Area 2[2]		CONE Area 3[3]	
July 2008 Dollars	**$000**	**$/kW**	**$000**	**$/kW**	**$000**	**$/kW**
Plant Proper EPC	$544,524	$906.18	$469,367	$781.11	$524,505	$872.87
Water and Sewer Interconnect	$5,000	$8.32	$5,000	$8.32	$5,000	$8.32
Electric Interconnect	$13,172	$21.92	$13,172	$21.92	$13,172	$21.92
Gas Interconnect	$5,997	$9.98	$5,997	$9.98	$5,997	$9.98
Equipment Spares	$2,794	$4.65	$2,794	$4.65	$2,794	$4.65
Owners Contingency	$27,226	$45.31	$23,468	$39.06	$26,225	$43.64
Mobilization and Startup	$4,930	$8.20	$4,930	$8.20	$4,930	$8.20
Land Purchase	$3,750	$6.24	$3,375	$5.62	$2,730	$4.54
Development Expenses	$7,509	$12.50	$7,509	$12.50	$7,509	$12.50
Legal Fees	$2,250	$3.74	$2,250	$3.74	$2,250	$3.74
Financial Fees	$6,797	$11.31	$5,928	$9.87	$6,531	$10.87
Interest During Construction	$51,711	$86.06	$45,057	$74.98	$49,938	$83.11
Air, EIS, Land Use & FERC Permits	$765	$1.27	$765	$1.27	$765	$1.27
Emissions Reductions Credits	$3,232	$5.38	$3,232	$5.38	$728	$1.21
Total Project Cost	$679,657	$1,131.06	$592,846	$986.60	$653,075	$1,086.83

PJM REGION	CONE Area 1[1]		CONE Area 2[2]		CONE Area 3[3]	
July 2010 Dollars	**$000**	**$/kW**	**$000**	**$/kW**	**$000**	**$/kW**
Plant Proper EPC	$555,637	$924.67	$477,558	$794.74	$534,784	$889.97
Water and Sewer Interconnect	$4,336	$7.22	$4,336	$7.22	$4,336	$7.22
Electric Interconnect	$10,951	$18.22	$10,951	$18.22	$10,951	$18.22
Gas Interconnect	$5,201	$8.66	$5,201	$8.66	$5,201	$8.66
Equipment Spares	$3,220	$5.36	$3,220	$5.36	$3,220	$5.36
Owners Contingency	$27,782	$46.23	$23,878	$39.74	$26,739	$44.50
Mobilization and Startup	$4,981	$8.29	$4,981	$8.29	$4,981	$8.29
Land Purchase	$3,255	$5.42	$3,027	$5.04	$2,315	$3.85
Development Expenses	$7,605	$12.66	$7,605	$12.66	$7,605	$12.66
Legal Fees	$2,279	$3.79	$2,279	$3.79	$2,279	$3.79
Financial Fees	$6,936	$11.54	$6,036	$10.04	$6,615	$11.01
Interest During Construction	$52,408	$87.22	$45,497	$75.71	$50,562	$84.14
Air, EIS, Land Use & FERC Permits	$1,040	$1.73	$1,040	$1.73	$1,040	$1.73
Emissions Reductions Credits	$7,959	$13.24	$7,959	$13.24	$826	$1.37
Total Project Cost	$693,591	$1,154.25	$603,567	$1,004.44	$661,455	$1,100.77

[1] CONE Area 1 encompasses the PS, JCP&L, AE, PECO, DPL and RECO zones.

[2] CONE Area 2 encompasses the BGE and PEPCO zones.

[3] CONE Area 3 encompasses the AEP, APS, ATSI, Dayton, DEOK, Duquesne and ComEd zones.

4.0 Plant Performance

4.1 Plant Net Capacity and Heat Rate

Pasteris Energy utilized GE Energy Services GateCycle power plant performance software to determine the performance of the CONE CC power plant at ambient temperatures from 10 °F to 100 °F. The performance evaluation also included detailed determinations of the plant parasitic load for the wet cooling tower fans, cooling water circulation pumps, boiler feed water pumps and the balance of plant axillaries. Plant performance is provided with the HRSG duct burners unfired and in the maximum fired operating mode. Table 4 below summarizes the plant performance for the CONE CC power plant in the unfired mode and Table 5 in the maximum fired mode.

Table 4

PJM CONE COMBINED CYCLE PLANT PERFORMANCE - UNFIRED DUCT BURNERS
EVAPORATIVE CT INLET AIR COOLING - NATURAL GAS

AMBIENT CONDITIONS										
Ambient Temperature (F)	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	90.0	100.0
PLANT GROSS CAPACITY										
CT 1 Output (MW)	185.358	182.135	178.912	175.233	171.440	167.769	165.184	160.979	154.342	147.706
CT 2 Output (MW)	185.358	182.135	178.912	175.233	171.440	167.769	165.184	160.979	154.342	147.706
STG Output MW)	192.260	193.304	194.347	195.177	195.954	196.531	195.309	192.704	188.026	183.347
Total Gross Output	562.976	557.573	552.171	545.643	538.835	532.068	525.677	514.662	496.710	478.759
PLANT PARASITIC LOADS										
Parasitic Load (MW)	11.260	11.426	11.592	11.620	11.614	11.607	11.595	11.574	11.539	11.504
Step-Up Transformer Losses (MW)	2.252	2.230	2.209	2.183	2.155	2.128	2.103	2.059	1.987	1.915
Total Parasitic Load (MW)	13.512	13.656	13.801	13.803	13.769	13.735	13.698	13.633	13.526	13.419
PLANT NET CAPACITY										
Net Plant Capacity (MW)	**549.464**	**543.917**	**538.370**	**531.841**	**525.066**	**518.333**	**511.979**	**501.029**	**483.185**	**465.340**
PLANT FUEL CONSUMPTION AND HEAT RATE										
CT 1 Fuel (MMBTU/Hr) (LHV)	1,735.3	1,711.0	1,686.7	1,660.9	1,634.6	1,609.3	1,592.4	1,564.6	1,520.6	1,476.6
CT 2 Fuel (MMBTU/Hr) (LHV)	1,735.3	1,711.0	1,686.7	1,660.9	1,634.6	1,609.3	1,592.4	1,564.6	1,520.6	1,476.6
Duct Burner 1 Fuel (MMBTU/Hr) (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner 2 Fuel (MMBTU/Hr) (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Plant Fuel (MMBTU/Hr) (LHV)	3,470.7	3,422.1	3,373.4	3,321.7	3,269.2	3,218.6	3,184.7	3,129.2	3,041.2	2,953.2
Total Plant Fuel (MMBTU/Hr) (HHV)	3,842.1	3,788.2	3,734.4	3,677.2	3,619.1	3,563.0	3,525.5	3,464.0	3,366.6	3,269.2
CT Heat Rate (BTU/kWh) (LHV)	9,224	9,255	9,288	9,338	9,394	9,451	9,497	9,576	9,707	9,849
CT Heat Rate (BTU/kWh) (HHV)	10,211	10,246	10,282	10,337	10,399	10,462	10,514	10,600	10,745	10,903
Net Plant Heat Rate (BTU/kWh) (LHV)	6,317	6,292	6,266	6,246	6,226	6,210	6,220	6,246	6,294	6,346
Net Plant Heat Rate (BTU/kWh) (HHV)	**6,992**	**6,965**	**6,936**	**6,914**	**6,893**	**6,874**	**6,886**	**6,914**	**6,968**	**7,025**

Table 5

PJM CONE COMBINED CYCLE PLANT PERFORMANCE - FIRED DUCT BURNERS
EVAPORATIVE CT INLET AIR COOLING - NATURAL GAS

AMBIENT CONDITIONS										
Ambient Temperature (F)	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	90.0	100.0
PLANT GROSS CAPACITY										
CT 1 Output (MW)	185.046	181.821	178.597	174.972	171.247	167.636	165.041	160.820	154.162	147.503
CT 2 Output (MW)	185.046	181.821	178.597	174.972	171.247	167.636	165.041	160.820	154.162	147.503
STG Output (MW)	312.735	312.857	312.979	313.000	312.996	312.993	312.998	313.004	313.007	313.011
Total Gross Output (MW)	682.827	676.500	670.172	662.944	655.490	648.264	643.080	634.644	621.331	608.017
PLANT PARASITIC LOADS										
Parasitic Load (MW)	15.379	15.368	15.357	15.339	15.319	15.301	15.298	15.296	15.295	15.293
Step-Up Transformer Losses (MW)	2.731	2.706	2.681	2.652	2.622	2.593	2.572	2.539	2.485	2.432
Total Parasitic Load (MW)	18.110	18.074	18.038	17.991	17.941	17.894	17.871	17.835	17.780	17.725
PLANT NET CAPACITY										
Net Plant Capacity (MW)	**664.717**	**658.426**	**652.135**	**644.953**	**637.549**	**630.370**	**625.209**	**616.810**	**603.551**	**590.292**
PLANT FUEL CONSUMPTION AND HEAT RATE										
CT 1 Fuel (MMBTU/Hr) (LHV)	1,734.3	1,710.0	1,685.7	1,660.0	1,634.0	1,608.9	1,591.8	1,564.0	1,520.0	1,476.0
CT 2 Fuel (MMBTU/Hr) (LHV)	1,734.3	1,710.0	1,685.7	1,660.0	1,634.0	1,608.9	1,591.8	1,564.0	1,520.0	1,476.0
Duct Burner 1 Fuel (MMBTU/Hr) (LHV)	459.6	455.1	450.7	447.3	444.3	441.9	446.4	455.3	470.9	486.6
Duct Burner 2 Fuel (MMBTU/Hr) (LHV)	459.6	455.1	450.7	447.3	444.3	441.9	446.4	455.3	470.9	486.6
Total Plant Fuel (MMBTU/Hr) (LHV)	4,387.9	4,330.3	4,272.8	4,214.7	4,156.6	4,101.7	4,076.3	4,038.5	3,981.9	3,925.2
Total Plant Fuel (MMBTU/Hr) (HHV)	4,857.4	4,793.7	4,730.0	4,665.7	4,601.3	4,540.5	4,512.5	4,470.6	4,407.9	4,345.2
CT Heat Rate (BTU/kWh) (LHV)	9,234	9,266	9,299	9,347	9,401	9,456	9,502	9,581	9,714	9,859
CT Heat Rate (BTU/kWh) (HHV)	10,222	10,257	10,294	10,347	10,407	10,468	10,519	10,606	10,753	10,914
Net Plant Heat Rate (BTU/kWh) (LHV)	6,601	6,577	6,552	6,535	6,520	6,507	6,520	6,547	6,597	6,650
Net Plant Heat Rate (BTU/kWh) (HHV)	**7,307**	**7,281**	**7,253**	**7,234**	**7,217**	**7,203**	**7,218**	**7,248**	**7,303**	**7,361**
Incremental Output Over Unfired (MW)	**115.3**	**114.5**	**113.8**	**113.1**	**112.5**	**112.0**	**113.2**	**115.8**	**120.4**	**125.0**
Incremental Heat Rate Over Unfired (HHV)	**8,809**	**8,781**	**8,751**	**8,740**	**8,732**	**8,725**	**8,717**	**8,694**	**8,651**	**8,611**

4.2 NOx Emissions Controls

The CONE CC power plant utilized dry low NOx ("DLN") combustor technology to control NOx at 9 PPM and CO also to 9 PPM exiting the CT while firing natural gas. While firing distillate kerosene water injection is used to control the NOx level at 42 PPM. Selective Catalytic Reduction ("SCR") technology and CO catalytic converters were employed to further reduce NOx and CO to 2.0 PPM exiting the stack, respectively.

4.3 Ancillary Services

The 600 MW CONE CC power plant is capable of supplying reactive power as an ancillary service. No additional capital cost is included for this service as leading power factor capability is standard design for the electric generators. Black start capability is not included in the CONE CC power plant as the unit is not started via a separate motor driven hydraulic system but utilizes the generator winding as a motor to start the unit using electric from the system. The required installed oil fired diesel generator capacity exceeds 12.0 MW to start a 600 MW combined cycle power plant and was deemed not cost effective. Accordingly, there are no black start revenues for the CONE CC power plant.

5.0 Annual Fixed Operating Expenses

5.1 Operations and Maintenance Staffing

WGPO provided the O&M staffing and expense for the CONE CC power plant. The staffing complement for the CONE CC power plant is twenty-three (23) on-site personnel. A 53.27% benefits and G&A burden was added to the base hourly rate. Also selected overtime of 18% to 22% above the base 2,080 hours were included at a time and one half hourly rates. This results in a 2008 fully loaded annual labor expense of $3,149,096 or $136,917 per person per year for the CONE CC power plant. These costs are for the New Jersey plant site. Costs for the Maryland and Illinois plant sites are slightly different due to adjustments in regional labor rates.

The 2010 O&M staffing and expenses were updated by WGPO. This resulted in a cost of $3,207,282. These costs are for the New Jersey plant site. Costs for the Maryland and Illinois plant sites are slightly different due to adjustments in regional labor rates.

5.2 Contract Parts and Labor

WGPO provided the annual contract parts and labor expenses for the 2008 CONE CC power plant which amounted to $1,494,888. This line item was also undated by WGPO for 2010 and did not change from the 2008 values as a result of the economic downturn.

5.3 Insurance Expenses

Overall power plant annual insurance premiums were estimated to be 0.5% of the insured asset value. Insurance was extended to the plant proper, the electric interconnection, the gas interconnection and capitalized spare parts. Coverage included general liability, property, boiler and machinery and business interruption. This amounts to approximately $2.85 Million annual premium for the CONE CC power plant at the New Jersey site in 2008. Insurance premiums varied slightly for the Maryland and Illinois sites based on plant asset value. Guidelines for the determination of insurance premiums were provided by Moore-McNeil LLC Insurance Consulting of Nashville, Tennessee. The same annual insurance premium factor of 0.5% of the insured asset value was used for 2010.

5.4 Property Tax

In the original 2005 CONE study property taxes were determined for plant site locations in New Jersey, Maryland and Illinois by obtaining public information on actual taxes paid by recently constructed power plant. This information was obtained from FERC filings or directly from the township or county tax assessors. These rates for power plants were compared with statutory tax rates in the counties and townships where the plants were constructed as well as surrounding counties and townships. In all cases the power plant tax rates were lower then the statutory rates indicating that development/enterprise zone tax relief was made available or payments in lieu of taxes ("PILOT") were negotiated. The average of the actual tax rates incurred by the power plants surveyed in each region was used in this study. For New Jersey the 2005 tax rate was $2.53 per $1,000 of assessed value, for Maryland the tax rate was $4.50 per $1,000 of assessed value and for Illinois the tax rate was $2.09 per $1,000 of assessed value. The assessed value was determined to be all fixed assets based on the plant proper construction capital cost and all interconnection costs plus net current assets which would include capitalized spare parts.

For the 2008 and 2010 CONE CC power plant the same methodology was used as in 2005. The survey of current tax rates determined that property tax rates increased only in New Jersey to $2.978 per $1,000 in 2008 and to $3.196 per $1,000 in 2010. Property tax rates in Maryland declined to $4.456 per $1,000 in 2008 and to $4.361 per $1,000 in 2010. Illinois declined to $1.908 per $1,000 in 2008 and remained at $1.908 per $1,000 in 2010.

5.5 General and Administrative Expenses

General and administrative expense cover any technical, legal, accounting and permitting fees incurred on an annual basis. Annual G&A expenses were estimated by WGPO at $615,715. This line item was also undated by WGPO for 2010 and did not change from the 2008 values as a result of the economic downturn.

The detailed annual fixed O&M expenses for the first year of operation for the CONE CC power plant are summarized on the following Table 6.

TABLE 6
PJM CONE CC POWER PLANT
GE FRAME 7FA TWO ON ONE CONFIGURATION
FIRST YEAR ANNUAL FIXED O&M EXPENSES BY PJM GEOGRAPHIC LOCATION

PJM REGION	CONE Area 1[1]			CONE AREA 2[2]			CONE Area 3[3]		
July 2010 Dollars	$000	$/MW-Day	$/MW-Year	$000	$/MW-Day	$/MW-Year	$000	$/MW-Day	$/MW-Year
Site O &M Labor	$3,149	$14.36	$5,241	$3,086	$14.07	$5,136	$3,055	$13.93	$5,083
O&M Contract Parts & Labor	$1,495	$6.82	$2,488	$1,495	$6.82	$2,488	$1,495	$6.82	$2,488
Electric Purchases	$300	$1.37	$499	$300	$1.37	$499	$300	$1.37	$499
Training-Employee Expenses	$129	$0.59	$215	$129	$0.59	$215	$129	$0.59	$215
O & M Management Fee	$300	$1.37	$499	$300	$1.37	$499	$300	$1.37	$499
Property, Machinery, B I Insurance	$2,857	$13.03	$4,755	$2,482	$11.31	$4,130	$2,757	$12.57	$4,589
G&A	$616	$2.81	$1,025	$616	$2.81	$1,025	$616	$2.81	$1,025
Property Taxes	$2,014	$9.18	$3,352	$2,627	$11.98	$4,372	$1,245	$5.68	$2,072
Total	$10,860	$49.52	$18,073	$11,034	$50.31	$18,363	$9,897	$45.12	$16,470

PJM REGION	CONE Area 1[1]			CONE AREA 2[2]			CONE Area 3[3]		
July 2012 Dollars	$000	$/MW-Day	$/MW-Year	$000	$/MW-Day	$/MW-Year	$000	$/MW-Day	$/MW-Year
Site O &M Labor	$3,207	$14.62	$5,337	$3,143	$14.33	$5,231	$3,111	$14.18	$5,177
O&M Contract Parts & Labor	$1,495	$6.82	$2,488	$1,495	$6.82	$2,488	$1,495	$6.82	$2,488
Electric Purchases	$304	$1.39	$506	$304	$1.39	$506	$304	$1.39	$506
Training-Employee Expenses	$129	$0.59	$215	$129	$0.59	$215	$129	$0.59	$215
O & M Management Fee	$300	$1.37	$499	$300	$1.37	$499	$300	$1.37	$499
Property, Machinery, B I Insurance	$2,897	$13.21	$4,821	$2,506	$11.43	$4,171	$2,792	$12.73	$4,647
G&A	$616	$2.81	$1,025	$616	$2.81	$1,025	$616	$2.81	$1,025
Property Taxes	$2,192	$9.99	$3,647	$2,598	$11.84	$4,323	$1,261	$5.75	$2,098
Total	$11,139	$50.79	$18,537	$11,091	$50.57	$18,456	$10,008	$45.63	$16,655

[1] CONE Area 1 encompasses the PS, JCP&L, AE, PECO, DPL and RECO zones.
[2] CONE Area 2 encompasses the BGE and PEPCO zones.
[3] CONE Area 3 encompasses the AEP, APS, ATSI, Dayton, DEOK, Duquesne and ComEd zones.

6.0 Financial Criteria

6.1 Proforma Analysis

A twenty (20) year after tax discounted cash flow ("ATDCF") model was used to determine the real levelized and levelized revenue requirements for the CONE CC power plant. Revenues determined covered capital recovery, annual fixed O&M expenses and earned the target IIR for the investor/owner. The mid-year convention was used to account for revenues and expenses incurred continuously throughout each year in the 20 year project evaluation. This methodology for evaluating power generation investments is the most commonly used by owners and developers. Accordingly, the financial results of this study will be consistent with the financial results obtained by developers when applying the CONE CC study capital costs, annual O&M expenses and financial criteria. The model only accounted for the capital costs to construct the plant and annual fixed operation and maintenance expenses of the project 20-year life. It includes, fixed revenue, annual fixed O&M expense, debt service, depreciation, income taxes and after tax cash flow. Variable operating expenses such as fuel and variable operations and maintenance expenses ("VOM") were not included in the model.

6.2 Financial Criteria

Target Internal Rate of Return

A target internal rate of return ("IRR") of 12% was chosen for the proforma evaluation and is based on achieving that IRR in year 20 of the project life. This target IRR has been used in all previous CONE studies.

Debt to Equity Ratio

A 50/50 debt to equity ratio was assumed in the proforma model evaluation. This ratio is consistent with the financial structure of a creditworthy integrated electric utility company or independent power company ("IPP"). This would be a reasonable financial structure for the CONE CC plant project and has been used in all previous CONE studies.

Debt Term and Interest Rate

Consistent with the financial structure of a creditworthy integrated electric utility company a long term, 20-year, bond with an interest rate of 7.0 % was used in the proforma model. A mortgage style loan was used which provides for increasing principal payment and decreasing interest payments over the loan term. This financial structure has been used in all previous CONE studies.

Tax Depreciation

The federal tax code allows for combined cycle power plants to utilize Modified Accelerated Cost Recovery System ("MACRS") over a 20 year tax life and 20 year tax life for combined cycle plants on the qualifying portions of the total project cost. Please note that a simple cycle power plant is allowed 15 year MACRS depreciation.

Federal and State Income Taxes

A 35.0% federal income tax rate was used in the proforma model. The state tax rate for New Jersey was 9.0 %, Maryland, 8.25% and Illinois 7.3%. Please note that Maryland has increased its tax rate from 7.0%.

Escalation

An annual escalation rate of 2.5% was assumed for all fixed expenses over the entire project life. This is consistent with all previous CONE studies.

Reporting of Revenue Requirements

Revenue requirements are presented in $/MW-Year and $/MW-Day and are total levelized. The total levelized value represents constant, non-escalating annual capacity revenues over the 20-year project life beginning in 2010 and having the same NPV as the 20-year revenue requirements escalating at 2.5% starting in 2010.

6.3 Proforma Evaluation Methodology

Initially an estimated real levelized annual revenue requirement was input into the proforma model. Next the capital cost and 2010 estimates of fixed O&M expenses were input into the proforma model and allowed to escalate at 2.5% annually to 2014, the first year of operation and for the 20-year project life. Added to these expenses were MACRS tax depreciation and debt interest payments. The difference between revenues and expenses provided the annual taxable income to which the federal income tax and appropriate state taxes were applied. This yielded after tax income. To the after tax income line the loan principal payments were subtracted and depreciation was added back to determine after tax cash flow. The equity placement of 50% of the total project cost was added as a negative cash flow on January 1, 2010 of the first operating year while annual cash flow was assigned a mid-year convention of July 1 for each year in the project life. This 20-year cash flow stream was used to calculate IRR via the MS Excel function XIIR. The levelized annual revenue requirement input was adjusted until the target 12.0% IRR was achieved. The model was then adjusted such that the annual revenues were total levelized meaning constant, non-escalating annual capacity revenues over the 20-year project life beginning in 2010. This non-escalating annual revenue was adjusted to obtain the target IRR of 12.0%

Addendum No. 1

Stantec 2010 and 2008 Capital Cost Reports

Combined Cycle Cost Estimate

2 x 1 GE 7FA Reference Plant

(2011 Update)

For

Pasteris Energy, Inc.

Prepared by:

Stantec Consulting Services, Inc.

February 2011

TABLE OF CONTENTS

1.0 Executive Summary

In 2008 Stantec Consulting Services, Inc. (formerly Industry and Energy Associates, LLC) was engaged by Pasteris Energy, Inc to provide capital cost estimates for a GE Frame 7FA dual fuel combined cycle plant located in three different geographical areas (Maryland, New Jersey, & Greater Chicago) in support of PJM's Cost of New Entry (CONE) analysis. In 2009 Monitoring Analytics (MA) requested that the New Jersey capital cost estimate be updated to reflect July 2009 pricing. This year MA has again requested the New Jersey capital cost estimate be updated to 2010 pricing.

As previously configured, the plant configuration consists of two (2) GE Frame 7FA dual fueled Combustion Turbine Generators (CTGs), two (2) duct fired three pressure reheat Heat Recovery Steam Generators (HRSGs) and one (1) condensing reheat Steam Turbine Generator (STG), surface condenser and all necessary Balance of Plant (BOP) equipment.

The revised capital cost estimate for the geographical area is included in the table below and the details of the cost breakdown are included in Section 4.0 of this report. For reference, the table also includes the previous cost estimates.

Geographical Area	Year	Labor Type	Total Installed Capital Cost
New Jersey	2010	Union	$555,600,000
New Jersey	2009	Union	$547,300,000
New Jersey	2008	Union	$544,500,000
Pricing Increase from 2010			$ 8,300,000

This new estimate represents a 1.5% increase from the previous year's price. Approximately 55% of the increase is due to the Power Island and Balance of Plant (BOP) equipment cost increases, 30% for construction cost increases, and the remaining 15% spread over engineering, contingency, and margin.

2.0 Development Approach

Capital Estimate

The original combined cycle power plant estimate Stantec developed was based on data from an Engineering, Procurement, & Construction (EPC) proposal for a similar configured power plant that Stantec had helped develop. This particular plant had the release date postponed several times, requiring Stantec to refresh the pricing in 2009. This revised pricing was used as the basis for the 2009 review effort. Although this project has still not been released there has not been any further pricing update. Therefore, for this year's pricing review Stantec utilized pricing information from another 2x1 GE 7FA project that we had worked on in the spring of 2010. Specifically, this work entailed a detailed review of a large well known contractor's EPC fixed price proposal to a major utility. The cost estimate available was quite detailed and allowed Stantec to perform a thorough examination of all major equipment, construction, and engineering costs.

Before discussing the Power Island pricing it is important to understand that GE is in the middle of a significant upgrade program to the 7FA turbine. Although the 7FA turbine has been up rated in performance over its inception in 1991 the unit has essentially maintained the same performance since 1999. This last version of the unit is now referred to as a 7FA.03 and was the basis of the original estimate. In 2010 GE introduced a new version of the turbine and labeled it the 7FA.04. This new unit increases the rated output from 175 MW to 183 MW (8 MW increase) and increases the efficiency from 36.2% to 38.0% (both referenced to ISO or standard conditions). Although this is a significant performance increase, GE has announced that the 7FA.04 is an interim machine and will be replaced by the 7FA.05 in 2012. The 7FA.05 will have a rated output of 211 MW and an efficiency of 38.5%, which is 33 MW output increase from the current 7FA.03. GE has further indicated that the 7FA.04 will be offered until the end of 2013 but the 7FA.05 will start shipment at the beginning of 2012.

From a July 2010 estimate perspective, the power plant would not come online any earlier then mid-2012 so the 7FA.03 would most likely not be available anymore and the 7FA.04 would be the model in production, although the 7FA.05 would have just entered production. For this updated estimate the 7FA.04 was selected as the unit of choice, as it would be the most likely selection from a production stand point and also was the basis of the contractor's 2010 EPC pricing we reviewed.

Last year's pricing for the three major components, the Combustion Turbine Generator (CTG), the Heat Recovery Steam Generator (HRSG), the Steam Turbine Generator (STG), the Continuous Emissions Monitoring System (CEMS) and the Distributed Control System (DCS) was based on direct feedback from General Electric (GE) providing a Power Island package. From an industry standpoint, obtaining a Power Island package is becoming more common as many EPC contractor's are trying to shed some project risk which, by using this equipment procurement methodology, shifts the performance and emission risk from the contractor to GE. However, this risk shift does increase the Power Island price versus the individual equipment pricing as GE adds a premium to provide this service. In theory, the EPC contractor risk money associated with this equipment should shift to the Power Island price, as they have less risk, but in reality this is not necessarily true as most contractor's will still retain some level of contingency and profit to the Power Island price. At this point in time, Stantec has not received any formal confirmation from GE on Power Island pricing for 2010 so instead we elected to adjust the EPC contractor's equipment pricing. Since this estimate was based on buying individual pieces of equipment versus a Power Island, Stantec shifted some of the contractor's engineering as well as contingency/profit to account for a Power Island price. We chose this estimating approach since we still believe buying a Power Island best represents the current methodology practiced by the majority of EPC contractors in the power field.

The Balance of Plant (BOP) equipment pricing from the 2010 EPC contractor's project estimate was cross checked with Stantec's 2009 estimate and adjusted accordingly. Where possible individual pieces of equipment were compared and in general the 2010 pricing was, as expected, higher than our 2009 estimate. Once finished with this analysis, the final BOP equipment pricing increased by approximately 1.5% from 2009.

The EPC contractor's engineering estimate was reviewed, adjusted for some work shifting to the Power Island supplier, and the final number was found to be marginally higher than Stantec's 2009 estimate. Stantec believes that, with the prospect of the market resurgence, most engineering firms would have made a minor price increase from 2009. Our opinion is that this labor rate increase equates to approximately a 1.5% from the 2009 engineering price, which is line with contractor's engineering estimate.

Comparison of the EPC contractor's construction estimate to the Stantec 2009 estimate was more difficult since every site is different and these nuances are difficult to extract from an estimate, plus every contractor has a different approach to estimating, and larger contractors tend to discretely include greater costs to cover higher corporate overhead costs. However, what was important was the number of craft labor hours assumed for each estimate was essentially the same, which further confirms the basis of the original construction estimate. With this information Stantec then updated the 2010 prevailing construction labor rates from the State of New Jersey Department of Labor and Workforce Development, which represented a ~2.2% increase. Construction material costs were also reviewed and increased approximately 2% to account for escalation.

The start-up costs carried in the EPC contractor's estimate were, in Stantec's opinion, too high. Our original start-up estimate was based on a reputable power plant start-up firm so we maintained the original estimate but updated the labor rates to match recent trends (~2.5%).

From a total project cost view point, once the scope and labor rate adjustments were made to the contractor's 2010 EPC estimate, it fell within 1-2% of the Stantec's estimate, which is well within the accuracy of either estimate and confirms the validity of both.

Stantec then tallied the capital cost estimate in a form similar to previous reports provided. Although only minor commercial changes (to reflect the later time period) were made to the basic cost assumptions made last year, they are repeated below for reference:

Commercial

- The cost estimate is based on utilizing union labor
- The cost estimates are based on a 50 hour construction work week
- Prices are in July 2010 dollars
- Freight is included
- Sales and Use Tax is excluded
- The cost of permits, local taxes, fees, etc, are excluded
- Costs for spare parts, fuel, electricity, chemicals, lubricants, etc is excluded
- Contingency is based on the following:
    - Equipment – 5%
    - Construction – 10%
- Margin (Profit) is based on the following:
    - Equipment (including Power Island) – 10%
    - Construction – 10%

Technical

- The combustion turbine is based on a GE 7FA.04 model
- The estimate is based on a level, greenfield site with no unusual site work required (i.e., blasting, rock removal, demolition, etc)
- The cycle configuration is based on wet cooling (cooling tower & surface condenser)
- The soil bearing pressure is high enough to permit the use of spreadfooting foundations, the use of piles is excluded
- The high side voltage of the main transformer is 230 kV
- The electrical scope concludes at the high side of the transformer, therefore transmission line and substation costs are by others
- The soil resistivity is low enough so a sacrificial anode type system will only be required for the natural gas piping and no other equipment or systems
- Natural gas is delivered at an adequate pressure and no gas compression is required
- Gas metering station is by others
- The majority of the plant will be installed outdoors with the exception of the STG, electrical equipment and water treatment. The STG will be housed in a “stick built” building. The electrical equipment and water treatment equipment will be housed in a pre-fabricated building.

3.0 Plant Description

Other than the new combustion turbine model selected, no other changes have been made to the power plant configuration used in Stantec's previous report. However, for reference purposes the plant description is reiterated below.

The proposed combined cycle power plant has a nominal generating capacity of 630 MW at 59 °F outdoor ambient temperature (Note this output was not increased for the new combustion turbine model as it was assumed the amount of duct firing needed to obtain this output would be reduced accordingly). The major components of the project include two (2) dual fueled GE Frame 7FA.04 Combustion Turbine Generators (CTGs) each with a dedicated Heat Recovery Steam Generator (HRSG), one (1) shared Steam Turbine Generator (STG), surface condenser, cooling tower, air pollution controls and associated auxiliary and control systems. The CTGs will be equipped with inlet evaporative coolers to increase power output at high ambient temperature. The HRSGs will generate steam at three pressure levels and will be equipped with duct burners to provide additional steam to augment power output. The plant will operate both on natural gas and distillate. The CTGs will be equipped with dry-low NOx combustors and the HRSGs with Selective Catalytic Reduction (SCR) control systems to reduce NOx emissions. The HRSGs will also be outfitted with oxidation catalyst systems to reduce CO and VOC emissions.

The termination points for the power facility are at the limits of the power facility and include the following:

- High Pressure natural gas supply downstream of the gas metering station (by others) at the power facility boundary
- Water from the municipal water supply at the power facility boundary
- Waste to the municipal sewer at the power facility boundary
- Electrical connection is at the high side (230 kV) of the transformer

The facility is assumed to be located on a Greenfield site. There will be three buildings included in the plant layout: an administration building, an electrical/water treatment building and a STG building. Buildings are of pre-fabricated construction with the exception of the STG building.

The following paragraphs describe each of the plant systems in more detail.

Ammonia System

The ammonia system stores and delivers ammonia to the Selective Catalytic Reduction (SCR) system. The major equipment consists of:

- Two (2) 100% ammonia forwarding pumps
- One (1) nominal 20,000 gallon horizontal tank
- Tank truck unloading area

Auxiliary Boiler

The auxiliary boiler is used when necessary to maintain water and metal temperatures in key components and to provide sealing steam to the steam turbines to enable more rapid starts. The major equipment consists of:

- One (1) 77,000 lb/hr Auxiliary Boiler
- Stack
- Deaerator
- Two (2) 100% capacity boiler feedpumps

Auxiliary Cooling Water

The auxiliary cooling water system is a closed loop cooling water system supplying cooling water to the gas turbine generator coolers, steam turbine lube oil coolers and other auxiliary equipment. The major equipment includes:

- Two (2) 100% Pumps
- Two (2) 100% Plate and Frame Heat Exchangers
- Surge Tank
- Chemical Addition Tank
- Piping, Valves and Instrumentation

Auxiliary Electrical

The Auxiliary Electrical system provides a means of stepping-down the generator terminal voltage to deliver power to the plant auxiliaries and equipment. Typical major equipment includes:

- Auxiliary cable and/or bus
- Station unit auxiliary transformers (UAT)
- 5 kV switchgear
- 5kV medium voltage motor controller gear (MVMC)
- Station service transformers (SST)
- secondary unit substations (SUS)
- 480 V motor control centers (MCC)

Boiler Blowdown

The boiler blowdown system collects the blowdown streams from the HRSGs and directs them to the blowdown tank for draining to plant drains. Additionally, startup blowdown, blowoffs, and other high temperature drains can be collected in the blowdown tank. The service water-cools the streams prior to flowing to the plant drains. The major equipment includes one (1) Blowdown Tank per HRSG provided with Power Island (by GE).

Circulating Water

The plant circulating water system provides cooling water for the condenser and for auxiliary cooling. Makeup water for the circulating water system is provided by the city and blowdown is sent to the municipal sewer system. The major equipment includes:

- Two (2) 50% circulating water pumps
- Multiple cell, mechanical draft cooling tower with pump basin
- Tower basin screens

- Level control valves
- Piping, valves and instrumentation

Combustion Turbine Generator (Power Island Scope)
The purpose of the Combustion Turbine Generator (CTG) is to supply electric and thermal energy. The system will include two (2) General Electric PG7241FA combustion turbine-generators (CTGs) packaged for outdoor installation. The major equipment includes two CTGS and accessories including:
- Combustion System (Natural Gas and Distillate fuel oil)
- Lubricating and Hydraulic Systems
- Water wash drain tank
- Exhaust System
- Inlet air system with noise abatement equipment
- Evaporative cooling system

Condensate
The condensate system receives turbine exhaust steam, turbine bypass steam and other miscellaneous steam drains then transports condensate from the hot well to the low-pressure drum of the HRSG. The condenser also provides a storage volume for other plant steam drains and the low-pressure, intermediate-pressure and high-pressure (cascading) steam turbine bypasses. The bypasses shall be designed for the steam turbine rapid startup and shutdown requirements. The major equipment includes:
- Three (3) 50% capacity Condensate Pumps with Motor Drives
- Condenser
- Gland Seal Condenser (provided with STG)
- Two (2) 100% capacity liquid ring mechanical vacuum pumps
- Control Valves and Instrumentation
- Piping and Valves

Chemical Feed
The purpose of the Chemical Feed system is to protect the HRSG from corrosion and scale formation and provide protection for the circulating water from scaling, biofouling and controlling pH. The major equipment includes:
- HRSG
  - Two (2) phosphate chemical feed skids with two (2) 100% HP & IP injection pumps, day tank if required, prepiped, prewired and including necessary components and accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).
  - One (1) Feedwater chemical feed skid with four (4) 100% injection pumps (oxygen scavenger & amine), day tank if required, prepiped, prewired and including necessary components and accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).
- Circulating Water

- One (1) acid chemical feed skid with two (2) 100% injection pumps, day tank, prepiped, prewired and including necessary components and accessories for a complete functional feed skid.
- One (1) corrosion control chemical feed skid with four (4) 100% injection pumps (two for dispersant & two for corrosion or scale inhibitor), day tank if required, prepiped, prewired and including necessary components and accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).
- One (1) biocide chemical feed skid with four (4) 100% injection pumps, prepiped, prewired and including necessary componenets and accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).

<u>Cathodic Protection</u>
A Cathodic Protection system shall mitigate galvanic or stray corrosion activity on the underground natural gas piping at the plant. The major equipment includes:
- Sacrificial anodes
- Cable
- Test boxes for potential measurement
- Insulating flanges.

<u>DC System</u>
The purpose of the DC System is to provide motive power and control power for certain normal and emergency equipment required for the safe shutdown of the plant and egress of all personnel during blackout conditions. These loads typically include control power for power circuit breakers, switchgear, protective relaying, and the Uninterruptible Power Supply (UPS), if applicable. The major equipment includes:
- Lead Acid storage battery
- Two 100% capacity battery chargers
- A DC distribution switchboard

<u>Diesel Generator</u>
The diesel generator provides emergency supply of essential plant auxiliary loads during an electrical system black out. The major equipment includes:
- 1,000 kw diesel generator w/ load bank
- 6,000 gallon diesel storage tank

<u>Demineralized Water</u>
The purpose of the Demineralized Water system is to provide make-up water to the condenser hotwell, evaporative cooling and for some of the CT wash water solutions. The deminerialized water system is sized to handle make-up when the plant is normally operating on natural gas. During back-up operation on oil a rental trailer must be brought in to keep up with the water injection demand. The major equipment that makes up the demineralized water treatment system including:
- Multimedia filters for prefiltration,
- Sodium bisulfite feed system

- Antiscalant chemical feed system
- Reverse Osmosis (RO) system
- Electrodeionization (EDI) polishing
- Two (2) 100 % capacity demineralized water pumps (gas operation only)
- 1,000,000 gallon demineralized water storage tank (~1 day storage when firing on oil)

<u>Distributed Control System </u>(Power Island Scope)
The Distributed Control System (DCS) will be a MARK VI control system provided by GE as part of the Power Island Package. The DCS shall control normal start-up, operation and shutdown of the Combustion and Steam Turbine Generators. All Balance of Plant (BOP) control shall also be from the DCS except that which is better suited for local control such as the Water Treatment System, Instrument Air Dryers, CEMs and miscellaneous sumps. Where local control is used, common trouble alarms to the DCS will be provided. Human Machine Interfaces (HMIs) shall be mounted in the Main Control Room and locally at each major piece of equipment.

The DCS shall consist of the following components:

- Gas Turbine Control
  - Triple Modular Redundancy (TMR)
  - Controller cabinets located in a controlled environment
  - Field wiring termination panels located at the machine and connected to the control cabinets with a redundant communication cable
  - HMI with ModBUS serial link for interfacing with DCS
  - Power Factor Controller
  - VAR Controller
  - Analog and Digital I/O for interfacing normal start-up, operation, and shutdown commands with DCS
  - The following unit control functions are provided by the Turbine Control System:
  - Manual and automatic synchronization
  - Breaker control and status indication
  - Metering for MW, MVAR, PF and Voltage
  - Load/Speed control
  - Power Factor control
- Steam Turbine Generator Control
  - Redundant CPUs
  - Controller cabinets located in a controlled environment
  - Field wiring junction boxes located at the machine and connected to the control cabinets with multi-conductor cable
  - HMI with ModBUS serial link for interfacing with DCS
  - Power Factor Controller
  - VAR Controller
  - Analog and Digital I/O for interfacing normal start-up, operation, and shutdown commands with DCS

- Balance of Plant Control
  - Regulatory and Discrete Control
  - Scanning, tagging, and engineering units conversion
  - Alarming of all configured system points
  - Interlocking and shutdown
  - Alarm summary displays
  - Demand report of all points in alarm, off scan, and alarms disabled
  - Faceplate display of loop controllers
  - Graphic P&ID type displays
  - Electrical one line type displays
  - Process overview displays
  - On-line system documentation
  - Application self documentation
  - Historical storage to support long term reporting and trending
  - Trending
  - Scheduled Reports
  - Simple Performance Calculations

Emissions Monitoring (Power Island Scope)
A fully certified Continuous Emissions Monitoring System (CEMS) shall be provided with the Power Island package (by GE) for each stack to determine emissions and generate reports. A Data Acquisition and Handling System (DAHS) shall be provided capable of reporting Emissions as required by the air permit.

Facility Electrical
The Facility Electrical system provides a power distribution system at various voltage levels for lighting, receptacles and small loads (motors, HVAC, etc.) as required for all buildings and site support facilities. The major equipment of this system includes:

- Transformers
- Distribution panelboards
- Disconnect switches
- Separately mounted motor starters
- General-purpose receptacles
- Welding receptacles
- Lighting

Fuel Gas System
The Fuel Gas system receives, compresses, regulates and transports natural gas supplied for use as fuel for the combustion turbines and duct burners. Natural gas shall be provided to the plant at the site boundary at an appropriate pressure. The major equipment of this system includes:

- Two (2) 100% Coalescing Filters
- One (1) 100% Scrubber
- Two (2) 50% Fuel Gas Performance Heaters (one per HRSG)
- Regulating and metering accessories

- Interconnecting power and instrument cable, piping, valves

<u>Fuel Oil System</u>
The fuel oil system receives, regulates and transports distillate oil for use as fuel for the combustion turbine. The major equipment includes:

- One (1) 1,000,000 gallon Fuel Oil Storage Tank with steel containment (over 1 day storage).
- Fuel Unloading Station
- Two (2) 100% capacity fuel forwarding pumps
- Two (2) 100% capacity fuel transfer pumps
- Interconnecting power and instrument cable, piping valves, filters and accessories

<u>Fire Protection</u>
The Fire Protection system provides standpipes and hose stations, fire extinguishers, independent fire detection systems, and fixed carbon dioxide suppression systems to protect personnel, plant buildings and equipment from the hazards of fire. The Fire Protection System shall be expanded as necessary. The system consists of the following:

- Low-pressure carbon dioxide fire suppression system
- Fire detection systems
- Portable fire extinguishers
- Manual fire alarm systems
- Manual pull stations in the Electrical Building
- Instrumentation and control equipment and a Fire Protection Control Panel for alarm, indication of system status, and actuation of fire protection equipment.
- One (1) 100% electric driven fire pump
- One (1) 100% diesel driven fire pump with diesel day tank.
- One (1) jockey pump
- 300,000 gallons of Fire Water reserve within the Raw Water Tank
- Piping and valves
- Fire pump building

<u>Feedwater</u>
The purpose of the Feedwater system is to pressurize and transfer deaerated condensate from the HRSG low-pressure drum to high and intermediate drum. The feedwater system will also be capable of providing feedwater to steam letdown stations during a steam bypass condition. The major components of the feedwater system include:

- Two (2) 100% Boiler Feed Pumps per HRSG (4 pumps total) with ARC valves
- Feedwater regulating control valves

<u>Grounding</u>
The Grounding system shall provide protection for personnel and equipment from the hazards that can occur during power system faults and lightning strikes. System design shall include the ability to detect system ground faults. The grounding system shall typically consist of copper-clad ground rods, bare and insulated copper cable, copper bus bars, copper wire mesh, exothermic connections, and air terminals.

Generation Electrical

The Generation Electrical system provides the means of delivering generator power to the Substation, and provides power for the Auxiliary Electrical system. One set of the following equipment shall be provided for each generating unit (Qty – 3).

- Generator main leads
- Generator breaker
- Generator step-up (GSU) transformer (230 kV)

Main Steam

The Main Steam system provides process steam to the Steam Turbine Generator. During normal operation steam shall flow from the HRSGs to the main steam headers into the steam turbine. The major equipment includes:

- Flow measuring equipment for steam flow
- Safety valves and vent piping
- Piping, valves and accessories

Oily Waste

The Oily Waste system collects oil-contaminated wastewater in the plant drains system. The oil waste system is gravity feed throughout the plant to an oil water separator. The solids and oil collected in this system will be collected for offsite disposal at a suitable, licensed, hazardous waste facility. The effluent from the oil/water separator will be discharged to the local sewer system.

Plant/Instrument Air

The Plant/Instrument Air system shall supply clean, dry, oil-free air at the required pressure and capacity for all pneumatic controls, transmitters, instruments and valve operators and clean compressed air for non-essential plant air requirements. The Plant/Instrument Air System consists of the following components:

- Two (2) full-capacity, air cooled, single stage, rotary screw type air compressors, each complete with controls, instrument panel, intercooler, lubrication system, aftercooler, moisture separator, intake filter-silencer, air/oil separator system and an unloading valve.
- Two (2) full capacity air receivers
- Two (2) full capacity, dual tower, heaterless type desiccant air dryers
- Two (2) full capacity prefilters
- Two (2) full capacity afterfilters
- Associated header and distribution piping and valves

Plant Communication

The Plant Communication system provides a plant external communication system through the use of a telephone system. As a minimum, the electrical building and control room shall include a telephone jack. The Owner shall provide any internal plant communication systems including, but not limited to, two-way radios.

Plant Security
The Plant Security system provides protection to the property and personnel. A security system consisting of card readers, intercoms motor operated gate and fencing will be provided.

Potable Water
The Potable Water system serves as a water source for drinking and personnel hygiene needs. Potable water also serves as a water source for eyewash and safety shower stations. Potable Water will be supplied from the local water utility.

Raw Water
The Raw Water system provides utility water for general plant use. The water will be provided by the local water utility. More specifically, the raw water system will supply water for miscellaneous non-potable plant uses including demineralized water system supply, plant equipment washdowns, makeup to the circulating water system and general service water and fire water. The major equipment includes

- One (1) 500,000 gallon Raw Water/Fire Water Tank
- Two (2) 100% capacity raw water pumps

Steam Generator (Power Island Scope)
The Heat Recovery Steam Generator (HRSG) shall generate high-quality steam, utilizing exhaust heat from each combustion turbine. The HRSG will be supplied as part of the Power Island purchase. The major components of each HRSG are as follows:

- Ductwork from combustion turbine
- Three pressure drums
- Low Pressure (LP) Economizer
- Low Pressure (LP) Evaporator
- Low Pressure (LP) Superheater
- Intermediate Pressure (IP) Economizer
- Intermediate Pressure (IP) Evaporator
- Intermediate Pressure (IP) Superheater
- High Pressure (HP) Evaporator
- High Pressure (HP) Economizer
- High Pressure (HP) Superheater
- Reheater
- Reheater Superheater
- Natural Gas fired ductburner
- Ductwork to stack
- 150 foot high, 18’6” diameter stack
- SCR system utilizing 19% aqueous ammonia
- CO Catalyst
- N_2 blanket connections

Sample System

The purpose of the sample system is to collect and analyze the various water supply streams to the HRSG and the key HRSG internal and output operating streams. The major equipment includes:

- One new sample panel/sink
- Sample coolers
- Analyzers
- Sample tubing, valves, fittings & supports
- Insulation and freeze protection
- Lab facilities necessary to provide analysis required herein

Steam Turbine (Power Island Scope)

The steam turbine generator provides electric power. This steam turbine is a multistage, reheat, condensing turbine. The turbine will have a downward exhaust with an expansion joint between the condenser and turbine. The major components include:

- Turbine
- Generator
- Stop/Control Valves
- Hydraulic Power Unit
- Lubrication System
- Steam seal and exhauster system
- Turbine Control System

Sanitary Waste

The Sanitary Waste system collects sanitary wastes from the plant and directs to the city sewer system.

Uninterruptible power supply

The Uninterruptible Power Supply (UPS) system shall provide regulated low voltage ac power to circuits that require non-interruptible and/or regulated ac power for the safe operation and monitoring of the equipment during both normal and transient operating conditions. The typical loads that are considered for connection to the UPS include the integrated control system, the turbine supervisory instrumentation, transducer power supplies, PLC or DCS, critical instruments, shutdown networks, and critical vendor supplied control panels. The UPS system consists of the following components:

- Static inverter
- Static transfer switch
- Alternate source transformer and line voltage regulator
- Manual make-before-break bypass switch
- Two ac circuit breakers (alternate input, and bypass source)
- One dc circuit breaker
- Vital 120 V ac distribution panel with fused disconnects
- Controls, indicating lights, meters and alarms to control the UPS

4.0 Cost Estimate

The Capital Cost Estimate for the combined cycle plant is attached. The cost estimate is based on the plant description included in Section 3.0, and the drawings included in Stantec's July 2008 report.

The new installed plant estimate is now $555,600,000 and has increased approximately $8.3 million (1.5%) from the July 2009 estimate. The breakdown below provides an indication where costs have changed:

• Power Island Equipment	$3.8 million
• Construction	$2.5 million
• Contingency & Profit	$1.0 million
• Plant Equipment	$0.7 million
• Other	$0.3 million
Total Increase	$8.3 million

PJM Study - 207FA EPC Estimate
(New Jersey - Camden to Atlantic City Area)

	207FA Plant Estimated February 2, 2011	
Division 1: General Conditions		
Construction Management	$ 9,990	
Construction Equipment	$ 6,323	
Temporary Facilities	$ 4,848	
Rework / Consumables	$ 7,877	
Performance Bond	$ 2,106	
		$ 31,144
Division 2: Site Work		
Site Preparation	$ 5,885	
Excavation	$ 1,634	
Dewatering	$ 300	
Roadways	$ 1,781	
Underground Piping	$ 5,538	
Underground Electrical	$ 3,941	
		$ 19,079
Division 3: Concrete		
Foundations	$ 15,842	
		$ 15,842
Division 4: Masonry	NA	
		NA
Division 5: Metals		
Steam Turbine Building	$ 4,020	
Misc Pre-Fabricated Buildings	$ 1,224	
Structural Steel	$ 1,323	
		$ 6,567
Division 6: Woods & Plastics	NA	
		NA
Division 7: Thermals		
Insulation	$ 2,400	
		$ 2,400
Division 8: Doors & Windows	NA	
		NA
Division 9: Finishes		
Painting	$ 300	
		$ 300
Division 10: Specialties	NA	
		NA
Division 11: Equipment		
Combustion Turbine	In Power Island	
HRSGs	In Power Island	
Steam Turbine	In Power Island	
Condenser	$ 3,273	
Cooling Tower	$ 6,000	
Pumps	$ 4,162	
Tanks	$ 4,785	
Water Treatment	$ 1,265	
Waste Water Treatment	$ 396	
Other Mechanical Equipment	$ 2,783	
General Escalation	$ 1,289	
Freight & Heavy Haul	$ 3,413	
		$ 27,366
Division 12: Furniture	NA	
		NA

PJM Study - 207FA EPC Estimate
(New Jersey - Camden to Atlantic City Area)

		207FA Plant Estimated February 2, 2011
Division 13: Special Construction		
Start-up Services	$ 2,786	
Start-up Costs	$ 1,556	
Plant Testing		
		$ 4,342
Division 14: Conveying	NA	
		NA
Division 15: Mechanical		
Above Ground Piping	$ 38,649	
Mechanical Equipment & Erection	$ 29,986	
		$ 68,635
Division 16: Electrical		
Main Transformers	$ 12,881	
Medium Voltage Equipment	$ 2,245	
Low Voltage Equipment	$ 1,510	
Bus Duct	$ 1,265	
Other Electrical Equipment	$ 700	
Electrical Installation	$ 33,054	
		$ 51,655
Division 17: Substation	NA	
		NA
Division 18: Instrument & Controls		
DCS	In Power Island	
CEMs	In Power Island	
Instrumentation & Control Valves	$ 3,443	
		$ 3,443
Division 19: Engineering		
Engineering	$ 12,180	
		$ 12,180
Subtotal:		**$ 242,953**
Commercial:		
Sales Tax	NA	
Insurance (General Liability)	$ 4,211	
Contigency Equipment (5%)	$ 2,406	
Contigency Construction (10%)	$ 18,193	
Margin Equipment (10%)	$ 5,182	
Margin Construction (10%)	$ 20,012	
Subtotal:		$ 50,004
Subtotal Contractor Price:		**$ 292,957**
GE Power Island, including:	$ 238,800	
Combustion Turbines (Qty 2)		$ 238,800
HRSGs (Qty 2)		
Steam Turbine (Qty 1)		
DCS (Qty 1)		
CEM (Qty 2)		
Contractor Margin on Power Island (10%)	$ 23,880	
		$ 23,880
Grand Total:		**$ 555,637**

Combined Cycle Cost Estimate

2 x 1 GE 7FA Reference Plant

For

Pasteris Energy, Inc.

Prepared by:

Industry and Energy Associates, LLC (IEA)

July 2008

TABLE OF CONTENTS

1.0 Executive Summary

Industry and Energy Associates, LLC (IEA) was engaged by Pasteris Energy, Inc to provide a capital cost estimate for a GE Frame 7FA dual fuel combined cycle plant in support of PJM's 2012 - 2013 capacity year auction. The plant configuration will consist of two (2) GE Frame 7FA dual fueled combustion turbine generators (CTGs), two (2) duct fired three pressure reheat Heat Recovery Steam Generators (HRSGs) and one (1) condensing reheat Steam Turbine Generator (STG), surface condenser and all necessary Balance of Plant (BOP) equipment.

As part of this effort, IEA developed the following:

- Capital costs for three (3) geographical areas (New Jersey, Greater Chicago and Maryland)
- General Arrangement drawing of a typical combined cycle plant
- Flow diagrams depicting typical combined cycle plant systems
- Typical Electrical One-Line Diagram
- Simple one page Project schedule
- Simple monthly construction draw down schedule

The capital cost estimates for each geographical area are included in the table below. The details of the cost breakdown for each location are included in Section 4.0.

The cost estimates are provided in June 2008 dollars with no escalation applied. Over the last several years the construction economy has seen escalating construction and commodity prices far exceeding historical inflation rates. Since 2004, the Turner Building Cost Index has seen over a 35% increase in the cost of non-residential construction costs. One specific example is the cost of copper. Copper was $0.60 per pound in 2004 and recently quoted at $3.99 per pound. Suppliers and vendors are not offering long term pricing validity with their proposals. Due to the recent volatility of prices any future escalation would be completely speculative.

Geographical Area	Labor Type	Total Installed Capital Cost
New Jersey	Union	$544,500,000
Greater Chicago	Union	$524,500,000
Maryland	Non-Union	$469,400,000

2.0 Development Approach

Capital Estimate

For the development of the capital cost estimate, IEA has utilized recent in-house data from a similarly configured project as described below in the plant description and on the attached drawings (Appendix A-C).

The pricing for the three major components, the Combustion Turbine Generator (CTG), the Heat Recovery Steam Generator (HRSG) and the Steam Turbine Generator (STG), is based on GE Power Island information obtained from an independent power producer who is developing a similarly configured plant for a 2010 delivery. This pricing is dramatically higher than numbers seen just a year ago and reflects both the recent spike in material costs and GE's speculation on the future material escalation. As a point of reference, IEA believes GE's pricing has increased approximately 25% from the previous year. Note GE's scope also includes the Continuous Emissions Monitoring System (CEMS) and the Distributed Control System (DCS) along with the associated equipment auxiliaries.

The costs for most Balance of Plant equipment including the surface condenser, cooling tower and generator step-up transformers were obtained from budgetary quotes received from vendors within the last three-month period. These budgetary quotes were solicited for a similar project via equipment specifications or datasheets. The proposals received were reviewed for technical acceptance, completeness and accuracy prior to inclusion in estimate. As a side note, the pricing validity received for all the bids varied from only a few days to at most a couple of weeks, which confirms the uncertainty in the market. For some minor equipment, IEA did not solicit budgetary pricing but used historical data and appropriately scaled to reflect current pricing.

Engineering and start-up costs were estimated for a typical 2 on 1 combined cycle project.

The power plant construction estimate was developed based on data from a recent EPC proposal and input obtained from multiple construction contractors. For this effort, the labor rates and productivity for three (3) geographical areas including New Jersey, Greater Chicago and Maryland were verified and used to develop the direct and indirect costs.

Over the last several years the construction economy has seen inflated construction and commodity prices far exceeding historical inflation rates. Since 2004, the Turner Building Cost Index has seen over a 35% increase in the cost of non-residential construction costs. One specific example is the cost of copper. Copper was $0.60 per pound in 2004 and recently quoted at $3.99 per pound. Recently suppliers and vendors are not offering long term pricing validity with their proposals. In fact some equipment pricing, with significant steel content, are being quoted with a validity of less then one week. Due to the recent volatility of prices any future escalation would be completely speculative. Therefore, the cost estimates are provided in June 2008 dollars with no escalation applied.

IEA then tallied the capital cost estimate in a form similar to previous reports provided to PJM. The following assumptions apply to the cost estimates:

Commercial

- The cost estimates are based on utilizing union labor for the Chicago and New Jersey areas and non-union for Maryland
- The cost estimates are based on a 50 hour construction work week
- Prices are in June 2008 dollars
- Freight is included
- Sales and Use Tax is excluded
- The cost of permits, local taxes, fees, etc, are excluded
- The GE Power Island price is based on information obtained from an independent power developer, which reflects equipment delivery in 2010
- Costs for spare parts, fuel, electricity, chemicals, lubricants, etc is excluded
- Contingency is based on the following:
    - Equipment – 5%
    - Construction – 10%
- Margin (Profit) is based on the following:
    - Equipment (including power island) – 10%
    - Construction – 10%

Technical

- The estimate is based on a level, greenfield site with no unusual site work required (i.e., blasting, rock removal, demolition, etc)
- The cycle configuration is based on wet cooling (cooling tower & surface condenser)
- The soil bearing pressure is high enough to permit the use of spreadfooting foundations, the use of piles is excluded
- The high side voltage of the main transformer is 230 kV
- The electrical scope concludes at the high side of the transformer, therefore transmission line and substation costs are by others
- The soil resistivity is low enough so a sacrificial anode type system will only be required for the natural gas piping and no other equipment or systems
- Natural gas is delivered at an adequate pressure and no gas compression is required
- Gas metering station is by others
- The majority of the plant will be installed outdoors with the exception of the STG, electrical equipment and water treatment. The STG will be housed in a "stick built" building. The electrical equipment and water treatment equipment will be housed in a pre-fabricated building.

Project Schedule

The project schedule developed (Appendix E) is based on current GE power island equipment deliveries, with the critical path being the steam turbine. With the recent upswing in the power market the steam turbine manufacturing shops are at full capacity. Thus, the turbine deliveries have gone from a more normal 22-24 month cycle to the current 30-month cycle. Other balance of plant equipment deliveries have also increased by several months but are overshadowed by the steam turbine delivery. In order to maintain any reasonable project schedule the power island equipment must be released prior to a Full Notice to Proceed (FNTP), which typically coincides with the project permit approval. This requires a significant down payment be made to GE to hold the manufacturing slot and release the forging material. Unfortunately, this extended delivery period is not expected to reverse for the next few years.

Since some system design work is required to specify the power island the schedule reflects a Limited Notice to Proceed (LNTP) where the contractor's engineer is partially released for several months. Full engineering release has been assumed to start at FNTP. One benefit of the extended equipment delivery is the chance for engineering to essentially be complete with the design prior to construction mobilization. This will reduce the rework in the field since the plant construction is not running in parallel with the design.

3.0 Plant Description

The proposed combined cycle power plant has a nominal generating capacity of 630 MW at 59 °F outdoor ambient temperature. The major components of the project include two (2) dual fueled GE Frame 7FA Combustion Turbine Generators (CTGs) each with a dedicated Heat Recovery Steam Generator (HRSG), one (1) shared Steam Turbine Generator (STG), surface condenser, cooling tower, air pollution controls and associated auxiliary and control systems. The CTGs will be equipped with inlet evaporative coolers to increase power output at high ambient temperature. The HRSGs will generate steam at three pressure levels and will be equipped with duct burners to provide additional steam to augment power output. The plant will operate both on natural gas and distillate. The CTGs will be equipped with dry-low NOx combustors and the HRSGs with Selective Catalytic Reduction (SCR) control systems to reduce NOx emissions. The HRSGs will also be outfitted with oxidation catalyst systems to reduce CO and VOC emissions.

The termination points for the power facility are at the limits of the power facility and include the following:

- High Pressure natural gas supply downstream of the gas metering station (by others) at the power facility boundary
- Water from the municipal water supply at the power facility boundary
- Waste to the municipal sewer at the power facility boundary
- Electrical connection is at the high side (230 kV) of the transformer

The facility is assumed to be located on a Greenfield site. There will be three buildings included in the plant layout: an administration building, an electrical/water treatment building and a STG building. Buildings are of pre-fabricated construction with the exception of the STG building. Layout of the plant shall be in accordance with the General Arrangement drawing included as Appendix A.

The following paragraphs describe each of the plant systems in more detail.

<u>Ammonia System</u>
The ammonia system stores and delivers ammonia to the Selective Catalytic Reduction (SCR) system. The major equipment consists of:

- Two (2) 100% ammonia forwarding pumps
- One (1) nominal 20,000 gallon horizontal tank
- Tank truck unloading area

<u>Auxiliary Boiler</u>
The auxiliary boiler is used when necessary to maintain water and metal temperatures in key components and to provide sealing steam to the steam turbines to enable more rapid starts. The major equipment consists of:

- One (1) 77,000 lb/hr Auxiliary Boiler
- Stack
- Deaerator

- Two (2) 100% capacity boiler feedpumps

Auxiliary Cooling Water
The auxiliary cooling water system is a closed loop cooling water system supplying cooling water to the gas turbine generator coolers, steam turbine lube oil coolers and other auxiliary equipment. The major equipment includes:
- Two (2) 100% Pumps
- Two (2) 100% Plate and Frame Heat Exchangers
- Surge Tank
- Chemical Addition Tank
- Piping, Valves and Instrumentation

Auxiliary Electrical
The Auxiliary Electrical system provides a means of stepping-down the generator terminal voltage to deliver power to the plant auxiliaries and equipment. Typical major equipment includes:
- Auxiliary cable and/or bus
- Station unit auxiliary transformers (UAT)
- 5 kV switchgear
- 5kV medium voltage motor controller gear (MVMC)
- Station service transformers (SST)
- secondary unit substations (SUS)
- 480 V motor control centers (MCC)

Boiler Blowdown
The boiler blowdown system collects the blowdown streams from the HRSGs and directs them to the blowdown tank for draining to plant drains. Additionally, startup blowdown, blowoffs, and other high temperature drains can be collected in the blowdown tank. The service water-cools the streams prior to flowing to the plant drains. The major equipment includes one (1) Blowdown Tank per HRSG provided with power island (by GE).

Circulating Water
The plant circulating water system provides cooling water for the condenser and for auxiliary cooling. Makeup water for the circulating water system is provided by the city and blowdown is sent to the municipal sewer system. The major equipment includes:
- Two (2) 50% circulating water pumps
- Multiple cell, mechanical draft cooling tower with pump basin
- Tower basin screens
- Level control valves
- Piping, valves and instrumentation

Combustion Turbine Generator (Power Island Scope)
The purpose of the Combustion Turbine Generator (CTG) is to supply electric and thermal energy. The system will include two (2) General Electric PG7241FA combustion

turbine-generators (CTGs) packaged for outdoor installation. The major equipment includes two CTGS and accessories including:

- Combustion System (Natural Gas and Distillate fuel oil)
- Lubricating and Hydraulic Systems
- Water wash drain tank
- Exhaust System
- Inlet air system with noise abatement equipment
- Evaporative cooling system

Condensate

The condensate system receives turbine exhaust steam, turbine bypass steam and other miscellaneous steam drains then transports condensate from the hot well to the low-pressure drum of the HRSG. The condenser also provides a storage volume for other plant steam drains and the low-pressure, intermediate-pressure and high-pressure (cascading) steam turbine bypasses. The bypasses shall be designed for the steam turbine rapid startup and shutdown requirements. The major equipment includes:

- Three (3) 50% capacity Condensate Pumps with Motor Drives
- Condenser
- Gland Seal Condenser (provided with STG)
- Two (2) 100% capacity liquid ring mechanical vacuum pumps
- Control Valves and Instrumentation
- Piping and Valves

Chemical Feed

The purpose of the Chemical Feed system is to protect the HRSG from corrosion and scale formation and provide protection for the circulating water from scaling, biofouling and controlling pH. The major equipment includes:

- HRSG
  - Two (2) phosphate chemical feed skids with two (2) 100% HP & IP injection pumps, day tank if required, prepiped, prewired and including necessary components and accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).
  - One (1) Feedwater chemical feed skid with four (4) 100% injection pumps (oxygen scavenger & amine), day tank if required, prepiped, prewired and including necessary components and accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).
- Circulating Water
  - One (1) acid chemical feed skid with two (2) 100% injection pumps, day tank, prepiped, prewired and including necessary components and accessories for a complete functional feed skid.
  - One (1) corrosion control chemical feed skid with four (4) 100% injection pumps (two for dispersant & two for corrosion or scale inhibitor), day tank if required, prepiped, prewired and including necessary components and

accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).

- One (1) biocide chemical feed skid with four (4) 100% injection pumps, prepiped, prewired and including necessary componenets and accessories for a complete functional feed skid. Chemical totes shall be provided by others (proprietary chemical vendor).

Cathodic Protection
A Cathodic Protection system shall mitigate galvanic or stray corrosion activity on the underground natural gas piping at the plant. The major equipment includes:

- Sacrificial anodes
- Cable
- Test boxes for potential measurement
- Insulating flanges.

DC System
The purpose of the DC System is to provide motive power and control power for certain normal and emergency equipment required for the safe shutdown of the plant and egress of all personnel during blackout conditions. These loads typically include control power for power circuit breakers, switchgear, protective relaying, and the Uninterruptible Power Supply (UPS), if applicable. The major equipment includes:

- Lead Acid storage battery
- Two 100% capacity battery chargers
- A DC distribution switchboard

Diesel Generator
The diesel generator provides emergency supply of essential plant auxiliary loads during an electrical system black out. The major equipment includes:

- 1,000 kw diesel generator w/ load bank
- 6,000 gallon diesel storage tank

Demineralized Water
The purpose of the Demineralized Water system is to provide make-up water to the condenser hotwell, evaporative cooling and for some of the CT wash water solutions. The deminerialized water system is sized to handle make-up when the plant is normally operating on natural gas. During back-up operation on oil a rental trailer must be brought in to keep up with the water injection demand. The major equipment that makes up the demineralized water treatment system including:

- Multimedia filters for prefiltration,
- Sodium bisulfite feed system
- Antiscalant chemical feed system
- Reverse Osmosis (RO) system
- Electrodeionization (EDI) polishing
- Two (2) 100 % capacity demineralized water pumps (gas operation only)

- 1,000,000 gallon demineralized water storage tank (~1 day storage when firing on oil)

.

Distributed Control System (Power Island Scope)

The Distributed Control System (DCS) will be a MARK VI control system provided by GE as part of the Power Island Package. The DCS shall control normal start-up, operation and shutdown of the Combustion and Steam Turbine Generators. All Balance of Plant (BOP) control shall also be from the DCS except that which is better suited for local control such as the Water Treatment System, Instrument Air Dryers, CEMs and miscellaneous sumps. Where local control is used, common trouble alarms to the DCS will be provided. Human Machine Interfaces (HMIs) shall be mounted in the Main Control Room and locally at each major piece of equipment.

The DCS shall consist of the following components:

- Gas Turbine Control
  - Triple Modular Redundancy (TMR)
  - Controller cabinets located in a controlled environment
  - Field wiring termination panels located at the machine and connected to the control cabinets with a redundant communication cable
  - HMI with ModBUS serial link for interfacing with DCS
  - Power Factor Controller
  - VAR Controller
  - Analog and Digital I/O for interfacing normal start-up, operation, and shutdown commands with DCS
  - The following unit control functions are provided by the Turbine Control System:
  - Manual and automatic synchronization
  - Breaker control and status indication
  - Metering for MW, MVAR, PF and Voltage
  - Load/Speed control
  - Power Factor control
- Steam Turbine Generator Control
  - Redundant CPUs
  - Controller cabinets located in a controlled environment
  - Field wiring junction boxes located at the machine and connected to the control cabinets with multi-conductor cable
  - HMI with ModBUS serial link for interfacing with DCS
  - Power Factor Controller
  - VAR Controller
  - Analog and Digital I/O for interfacing normal start-up, operation, and shutdown commands with DCS
- Balance of Plant Control
  - Regulatory and Discrete Control
  - Scanning, tagging, and engineering units conversion
  - Alarming of all configured system points

- Interlocking and shutdown
- Alarm summary displays
- Demand report of all points in alarm, off scan, and alarms disabled
- Faceplate display of loop controllers
- Graphic P&ID type displays
- Electrical one line type displays
- Process overview displays
- On-line system documentation
- Application self documentation
- Historical storage to support long term reporting and trending
- Trending
- Scheduled Reports
- Simple Performance Calculations

Emissions Monitoring (Power Island Scope)
A fully certified Continuous Emissions Monitoring System (CEMS) shall be provided with the power island package (by GE) for each stack to determine emissions and generate reports. A Data Acquisition and Handling System (DAHS) shall be provided capable of reporting Emissions as required by the air permit.

Facility Electrical
The Facility Electrical system provides a power distribution system at various voltage levels for lighting, receptacles and small loads (motors, HVAC, etc.) as required for all buildings and site support facilities. The major equipment of this system includes:

- Transformers
- Distribution panelboards
- Disconnect switches
- Separately mounted motor starters
- General-purpose receptacles
- Welding receptacles
- Lighting

Fuel Gas System
The Fuel Gas system receives, compresses, regulates and transports natural gas supplied for use as fuel for the combustion turbines and duct burners. Natural gas shall be provided to the plant at the site boundary at an appropriate pressure. The major equipment of this system includes:

- Two (2) 100% Coalescing Filters
- One (1) 100% Scrubber
- Two (2) 50% Fuel Gas Performance Heaters (one per HRSG)
- Regulating and metering accessories
- Interconnecting power and instrument cable, piping, valves

Fuel Oil System

The fuel oil system receives, regulates and transports distillate oil for use as fuel for the combustion turbine. The major equipment includes:

- One (1) 1,000,000 gallon Fuel Oil Storage Tank with steel containment (over 1 day storage).
- Fuel Unloading Station
- Two (2) 100% capacity fuel forwarding pumps
- Two (2) 100% capacity fuel transfer pumps
- Interconnecting power and instrument cable, piping valves, filters and accessories

Fire Protection

The Fire Protection system provides standpipes and hose stations, fire extinguishers, independent fire detection systems, and fixed carbon dioxide suppression systems to protect personnel, plant buildings and equipment from the hazards of fire. The Fire Protection System shall be expanded as necessary. The system consists of the following:

- Low-pressure carbon dioxide fire suppression system
- Fire detection systems
- Portable fire extinguishers
- Manual fire alarm systems
- Manual pull stations in the Electrical Building
- Instrumentation and control equipment and a Fire Protection Control Panel for alarm, indication of system status, and actuation of fire protection equipment.
- One (1) 100% electric driven fire pump
- One (1) 100% diesel driven fire pump with diesel day tank.
- One (1) jockey pump
- 300,000 gallons of Fire Water reserve within the Raw Water Tank
- Piping and valves
- Fire pump building

Feedwater

The purpose of the Feedwater system is to pressurize and transfer deaerated condensate from the HRSG low-pressure drum to high and intermediate drum. The feedwater system will also be capable of providing feedwater to steam letdown stations during a steam bypass condition. The major components of the feedwater system include:

- Two (2) 100% Boiler Feed Pumps per HRSG (4 pumps total) with ARC valves
- Feedwater regulating control valves

Grounding

The Grounding system shall provide protection for personnel and equipment from the hazards that can occur during power system faults and lightning strikes. System design shall include the ability to detect system ground faults. The grounding system shall typically consist of copper-clad ground rods, bare and insulated copper cable, copper bus bars, copper wire mesh, exothermic connections, and air terminals.

Generation Electrical
The Generation Electrical system provides the means of delivering generator power to the Substation, and provides power for the Auxiliary Electrical system. One set of the following equipment shall be provided for each generating unit (Qty – 3).

- Generator main leads
- Generator breaker
- Generator step-up (GSU) transformer (230 kV)

Main Steam
The Main Steam system provides process steam to the Steam Turbine Generator. During normal operation steam shall flow from the HRSGs to the main steam headers into the steam turbine. The major equipment includes:

- Flow measuring equipment for steam flow
- Safety valves and vent piping
- Piping, valves and accessories

Oily Waste
The Oily Waste system collects oil-contaminated wastewater in the plant drains system. The oil waste system is gravity feed throughout the plant to an oil water separator. The solids and oil collected in this system will be collected for offsite disposal at a suitable, licensed, hazardous waste facility. The effluent from the oil/water separator will be discharged to the local sewer system.

Plant/Instrument Air
The Plant/Instrument Air system shall supply clean, dry, oil-free air at the required pressure and capacity for all pneumatic controls, transmitters, instruments and valve operators and clean compressed air for non-essential plant air requirements. The Plant/Instrument Air System consists of the following components:

- Two (2) full-capacity, air cooled, single stage, rotary screw type air compressors, each complete with controls, instrument panel, intercooler, lubrication system, aftercooler, moisture separator, intake filter-silencer, air/oil separator system and an unloading valve.
- Two (2) full capacity air receivers
- Two (2) full capacity, dual tower, heaterless type desiccant air dryers
- Two (2) full capacity prefilters
- Two (2) full capacity afterfilters
- Associated header and distribution piping and valves

Plant Communication
The Plant Communication system provides a plant external communication system through the use of a telephone system. As a minimum, the electrical building and control room shall include a telephone jack. The Owner shall provide any internal plant communication systems including, but not limited to, two-way radios.

Plant Security

The Plant Security system provides protection to the property and personnel. A security system consisting of card readers, intercoms motor operated gate and fencing will be provided.

Potable Water

The Potable Water system serves as a water source for drinking and personnel hygiene needs. Potable water also serves as a water source for eyewash and safety shower stations. Potable Water will be supplied from the local water utility.

Raw Water

The Raw Water system provides utility water for general plant use. The water will be provided by the local water utility. More specifically, the raw water system will supply water for miscellaneous non-potable plant uses including demineralized water system supply, plant equipment washdowns, makeup to the circulating water system and general service water and fire water. The major equipment includes

- One (1) 500,000 gallon Raw Water/Fire Water Tank
- Two (2) 100% capacity raw water pumps

Steam Generator (Power Island Scope)

The Heat Recovery Steam Generator (HRSG) shall generate high-quality steam, utilizing exhaust heat from each combustion turbine. The HRSG will be supplied as part of the Power Island purchase. The major components of each HRSG are as follows:

- Ductwork from combustion turbine
- Three pressure drums
- Low Pressure (LP) Economizer
- Low Pressure (LP) Evaporator
- Low Pressure (LP) Superheater
- Intermediate Pressure (IP) Economizer
- Intermediate Pressure (IP) Evaporator
- Intermediate Pressure (IP) Superheater
- High Pressure (HP) Evaporator
- High Pressure (HP) Economizer
- High Pressure (HP) Superheater
- Reheater
- Reheater Superheater
- Natural Gas fired ductburner
- Ductwork to stack
- 150 foot high, 18'6" diameter stack
- SCR system utilizing 19% aqueous ammonia
- CO Catalyst
- N_2 blanket connections

Sample System

The purpose of the sample system is to collect and analyze the various water supply streams to the HRSG and the key HRSG internal and output operating streams. The major equipment includes:

- One new sample panel/sink
- Sample coolers
- Analyzers
- Sample tubing, valves, fittings & supports
- Insulation and freeze protection
- Lab facilities necessary to provide analysis required herein

Steam Turbine (Power Island Scope)

The steam turbine generator provides electric power. This steam turbine is a multistage, reheat, condensing turbine. The turbine will have a downward exhaust with an expansion joint between the condenser and turbine. The major components include:

- Turbine
- Generator
- Stop/Control Valves
- Hydraulic Power Unit
- Lubrication System
- Steam seal and exhauster system
- Turbine Control System

Sanitary Waste

The Sanitary Waste system collects sanitary wastes from the plant and directs to the city sewer system.

Uninterruptible power supply

The Uninterruptible Power Supply (UPS) system shall provide regulated low voltage ac power to circuits that require non-interruptible and/or regulated ac power for the safe operation and monitoring of the equipment during both normal and transient operating conditions. The typical loads that are considered for connection to the UPS include the integrated control system, the turbine supervisory instrumentation, transducer power supplies, PLC or DCS, critical instruments, shutdown networks, and critical vendor supplied control panels. The UPS system consists of the following components:

- Static inverter
- Static transfer switch
- Alternate source transformer and line voltage regulator
- Manual make-before-break bypass switch
- Two ac circuit breakers (alternate input, and bypass source)
- One dc circuit breaker
- Vital 120 V ac distribution panel with fused disconnects
- Controls, indicating lights, meters and alarms to control the UPS

4.0 Cost Estimate

The Capital Cost Estimate for the combined cycle plant is attached. The cost estimate is based on the plant description included in Section 3.0, and the drawings included in Appendices A, B and C.

PJM Study - 207FA EPC Estimate
(New Jersey - Camden to Atlantic City Area)

	207FA Plant Estimated June 1, 2008	
Division 1: General Conditions		
Construction Management	$ 9,355	
Construction Equipment	$ 6,200	
Temporary Facilities	$ 4,848	
Rework / Consumables	$ 7,606	
Performance Bond	$ 2,025	
		$ 30,034
Division 2: Site Work		
Site Preparation	$ 5,500	
Excavation	$ 1,542	
Dewatering	$ 300	
Roadways	$ 1,749	
Underground Piping	$ 5,485	
Underground Electrical	$ 3,718	
		$ 18,294
Division 3: Concrete		
Foundations	$ 14,964	
		$ 14,964
Division 4: Masonry	NA	
		NA
Division 5: Metals		
Steam Turbine Building	$ 4,020	
Misc Pre-Fabricated Buildings	$ 1,209	
Structural Steel	$ 1,266	
		$ 6,495
Division 6: Woods & Plastics	NA	
		NA
Division 7: Thermals		
Insulation	$ 2,400	
		$ 2,400
Division 8: Doors & Windows	NA	
		NA
Division 9: Finishes		
Painting	$ 300	
		$ 300
Division 10: Specialties	NA	
		NA
Division 11: Equipment		
Combustion Turbine	In Power Island	
HRSGs	In Power Island	
Steam Turbine	In Power Island	
Condenser	$ 3,273	
Cooling Tower	$ 5,250	
Pumps	$ 4,559	
Tanks	$ 4,785	
Water Treatment	$ 1,025	
Waste Water Treatment	$ 396	
Other Mechanical Equipment	$ 2,945	
Freight & Heavy Haul	$ 3,147	
		$ 25,380
Division 12: Furniture	NA	
		NA

PJM Study - 207FA EPC Estimate
(New Jersey - Camden to Atlantic City Area)

	207FA Plant Estimated June 1, 2008	
Division 13: Special Construction		
Start-up Services	$ 2,640	
Start-up Costs	$ 1,511	
Plant Testing		
		$ 4,151
Division 14: Conveying	NA	
		NA
Division 15: Mechanical		
Above Ground Piping	$ 38,365	
Mechanical Equipment & Erection	$ 29,935	
		$ 68,300
Division 16: Electrical		
Main Transformers	$ 9,900	
Medium Voltage Equipment	$ 2,245	
Low Voltage Equipment	$ 1,510	
Bus Duct	$ 1,265	
Other Electrical Equipment	$ 700	
Electrical Installation	$ 31,109	
		$ 46,729
Division 17: Substation	NA	
		NA
Division 18: Instrument & Controls		
DCS	In Power Island	
CEMs	In Power Island	
Instrumentation & Control Valves	$ 3,443	
		$ 3,443
Division 19: Engineering		
Engineering	$ 12,000	
		$ 12,000
Subtotal:		**$ 232,490**
Commercial:		
Sales Tax	NA	
Insurance (General Liability)	$ 4,049	
Contigency Equipment (5%)	$ 2,222	
Contigency Construction (10%)	$ 17,665	
Margin Equipment (5%)	$ 4,667	
Margin Construction (10%)	$ 19,431	
Subtotal:		$ 48,034
Subtotal Contractor Price:		**$ 280,524**
GE Power Island, including:	$ 240,000	
Combustion Turbines (Qty 2)		$ 240,000
HRSGs (Qty 2)		
Steam Turbine (Qty 1)		
DCS (Qty 1)		
CEM (Qty 2)		
Contractor Margin on Power Island (5%)	$ 24,000	
		$ 24,000
Grand Total:		**$ 544,524**

PJM Study - 207FA EPC Estimate
(Chicago Area)

	207FA Plant Estimated June 1, 2008	
Division 1: General Conditions		
Construction Management	$ 9,355	
Construction Equipment	$ 6,200	
Temporary Facilities	$ 4,848	
Rework / Consumables	$ 6,413	
Performance Bond	$ 1,876	
		$ 28,692
Division 2: Site Work		
Site Preparation	$ 5,363	
Excavation	$ 1,489	
Dewatering	$ 300	
Roadways	$ 1,731	
Underground Piping	$ 5,026	
Underground Electrical	$ 3,213	
		$ 17,122
Division 3: Concrete		
Foundations	$ 14,303	
		$ 14,303
Division 4: Masonry	NA	
		NA
Division 5: Metals		
Steam Turbine Building	$ 4,020	
Misc Pre-Fabricated Buildings	$ 1,197	
Structural Steel	$ 1,262	
		$ 6,479
Division 6: Woods & Plastics	NA	
		NA
Division 7: Thermals		
Insulation	$ 2,400	
		$ 2,400
Division 8: Doors & Windows	NA	
		NA
Division 9: Finishes		
Painting	$ 300	
		$ 300
Division 10: Specialties	NA	
		NA
Division 11: Equipment		
Combustion Turbine	In Power Island	
HRSGs	In Power Island	
Steam Turbine	In Power Island	
Condenser	$ 3,273	
Cooling Tower	$ 5,250	
Pumps	$ 4,559	
Tanks	$ 4,785	
Water Treatment	$ 1,025	
Waste Water Treatment	$ 396	
Other Mechanical Equipment	$ 2,945	
Freight & Heavy Haul	$ 3,147	
		$ 25,380
Division 12: Furniture	NA	
		NA

PJM Study - 207FA EPC Estimate
(Chicago Area)

	207FA Plant Estimated June 1, 2008	
Division 13: Special Construction		
Start-up Services	$ 2,640	
Start-up Costs	$ 1,511	
Plant Testing		
		$ 4,151
Division 14: Conveying	NA	
		NA
Division 15: Mechanical		
Above Ground Piping	$ 33,978	
Mechanical Equipment & Erection	$ 26,009	
		$ 59,987
Division 16: Electrical		
Main Transformers	$ 9,900	
Medium Voltage Equipment	$ 2,245	
Low Voltage Equipment	$ 1,510	
Bus Duct	$ 1,265	
Other Electrical Equipment	$ 700	
Electrical Installation	$ 26,367	
		$ 41,987
Division 17: Substation	NA	
		NA
Division 18: Instrument & Controls		
DCS	In Power Island	
CEMs	In Power Island	
Instrumentation & Control Valves	$ 3,443	
		$ 3,443
Division 19: Engineering		
Engineering	$ 12,000	
		$ 12,000
Subtotal:		**$ 216,244**
Commercial:		
Sales Tax	NA	
Insurance (General Liability)	$ 3,751	
Contigency Equipment (5%)	$ 2,222	
Contigency Construction (10%)	$ 16,010	
Margin Equipment (5%)	$ 4,667	
Margin Construction (10%)	$ 17,611	
Subtotal:		$ 44,261
Subtotal Contractor Price:		**$ 260,505**
GE Power Island, including:	$ 240,000	
Combustion Turbines (Qty 2)		$ 240,000
HRSGs (Qty 2)		
Steam Turbine (Qty 1)		
DCS (Qty 1)		
CEM (Qty 2)		
Contractor Margin on Power Island (5%)	$ 24,000	
		$ 24,000
Grand Total:		**$ 524,505**

PJM Study - 207FA EPC Estimate
(Maryland Area)

	207FA Plant Estimated June 1, 2008	
Division 1: General Conditions		
Construction Management	$ 6,310	
Construction Equipment	$ 6,200	
Temporary Facilities	$ 4,848	
Rework / Consumables	$ 3,295	
Performance Bond	$ 1,486	
		$ 22,139
Division 2: Site Work		
Site Preparation	$ 3,759	
Excavation	$ 1,028	
Dewatering	$ 300	
Roadways	$ 1,573	
Underground Piping	$ 3,831	
Underground Electrical	$ 2,114	
		$ 12,605
Division 3: Concrete		
Foundations	$ 10,358	
		$ 10,358
Division 4: Masonry	NA	
		NA
Division 5: Metals		
Steam Turbine Building	$ 4,020	
Misc Pre-Fabricated Buildings	$ 1,136	
Structural Steel	$ 1,252	
		$ 6,408
Division 6: Woods & Plastics	NA	
		NA
Division 7: Thermals		
Insulation	$ 2,400	
		$ 2,400
Division 8: Doors & Windows	NA	
		NA
Division 9: Finishes		
Painting	$ 300	
		$ 300
Division 10: Specialties	NA	
		NA
Division 11: Equipment		
Combustion Turbine	In Power Island	
HRSGs	In Power Island	
Steam Turbine	In Power Island	
Condenser	$ 3,273	
Cooling Tower	$ 5,250	
Pumps	$ 4,559	
Tanks	$ 4,785	
Water Treatment	$ 1,025	
Waste Water Treatment	$ 396	
Other Mechanical Equipment	$ 2,945	
Freight & Heavy Haul	$ 3,147	
		$ 25,380
Division 12: Furniture	NA	
		NA

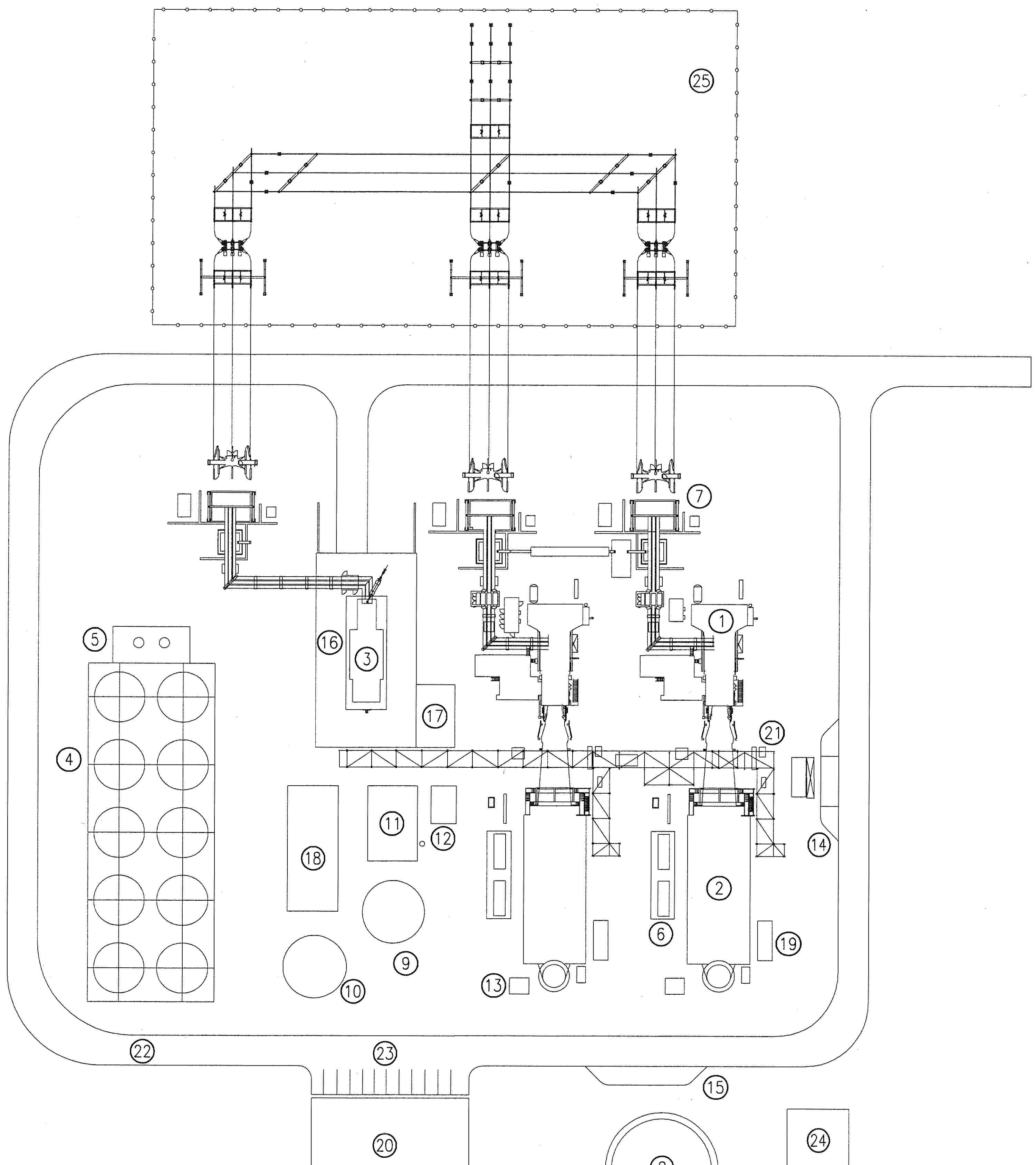
PJM Study - 207FA EPC Estimate
(Maryland Area)

		207FA Plant Estimated June 1, 2008	
Division 13: Special Construction			
Start-up Services	$ 2,640		
Start-up Costs	$ 1,511		
Plant Testing			
		$ 4,151	
Division 14: Conveying	NA		
		NA	
Division 15: Mechanical			
Above Ground Piping	$ 21,212		
Mechanical Equipment & Erection	$ 17,047		
		$ 38,259	
Division 16: Electrical			
Main Transformers	$ 9,900		
Medium Voltage Equipment	$ 2,245		
Low Voltage Equipment	$ 1,510		
Bus Duct	$ 1,265		
Other Electrical Equipment	$ 700		
Electrical Installation	$ 17,648		
		$ 33,268	
Division 17: Substation	NA		
		NA	
Division 18: Instrument & Controls			
DCS	In Power Island		
CEMs	In Power Island		
Instrumentation & Control Valves	$ 3,443		
		$ 3,443	
Division 19: Engineering			
Engineering	$ 12,000		
		$ 12,000	
Subtotal:		**$ 170,711**	
Commercial:			
Sales Tax	NA		
Insurance (General Liability)	$ 3,715		
Contigency Equipment (5%)	$ 2,222		
Contigency Construction (10%)	$ 11,453		
Margin Equipment (5%)	$ 4,667		
Margin Construction (10%)	$ 12,599		
Subtotal:		$ 34,656	
Subtotal Contractor Price:		**$ 205,367**	
GE Power Island, including:	$ 240,000		
Combustion Turbines (Qty 2)		$ 240,000	
HRSGs (Qty 2)			
Steam Turbine (Qty 1)			
DCS (Qty 1)			
CEM (Qty 2)			
Contractor Margin on Power Island (5%)	$ 24,000		
		$ 24,000	
Grand Total:		**$ 469,367**	

5.0 APPENDIX

APPENDIX A

Power Plant General Arrangement



LEGEND

1	COMBUSTION TURBINE GENERATOR
2	HEAT RECOVERY STEAM GENERATOR
3	STEAM TURBINE GENERATOR
4	COOLING TOWER
5	CIRCULATING WATER PUMPS
6	BOILER FEEDWATER PUMPS
7	STEP-UP TRANSFORMER
8	FUEL OIL TANK AND DIKE
9	RAW/FIRE WATER TANK
10	DEMINERALIZED WATER TANK
11	AUXILIARY BOILER AREA
12	EMERGENCY DIESEL GENERATOR
13	CONTINUOUS EMISSION MONITORING
14	AMMONIA TANK AND UNLOADING AREA
15	FUEL OIL UNLOADING AREA
16	STEAM TURBINE BUILDING
17	ELECTRIC ROOM (BELOW) / CONTROL ROOM (ABOVE)
18	WATER TREATMENT / ELECTRIC BUILDING
19	AMMONIA VAPORIZER SKID
20	ADMINISTRATION / WAREHOUSE BUILDING
21	PIPE RACK
22	PLANT ACCESS ROAD
23	PARKING
24	GAS METERING SYSTEM (BY OTHERS)
25	SWITCHYARD (BY OTHERS)

NOTES:

PRELIMINARY

7/9/08

20' 0 20' 40' 60' 80' 100'

SCALE: 1" = 50'-0"

REV	DATE	STATUS	BY	CHK	P.E.

APPROVED BY:

ENGINEERED BY: LKP

DRAWN BY: CMB

DATE: 6/25/08

SCALE: 1"=40'

C.O.A.

industry and energy associates
27 Pearl Street
Portland, ME 04101

CONT./PROJ. No. 08027

PJM – GE 207FA REFERENCE PLANT

PASTERIS ENERGY, INC.

SITE LAYOUT

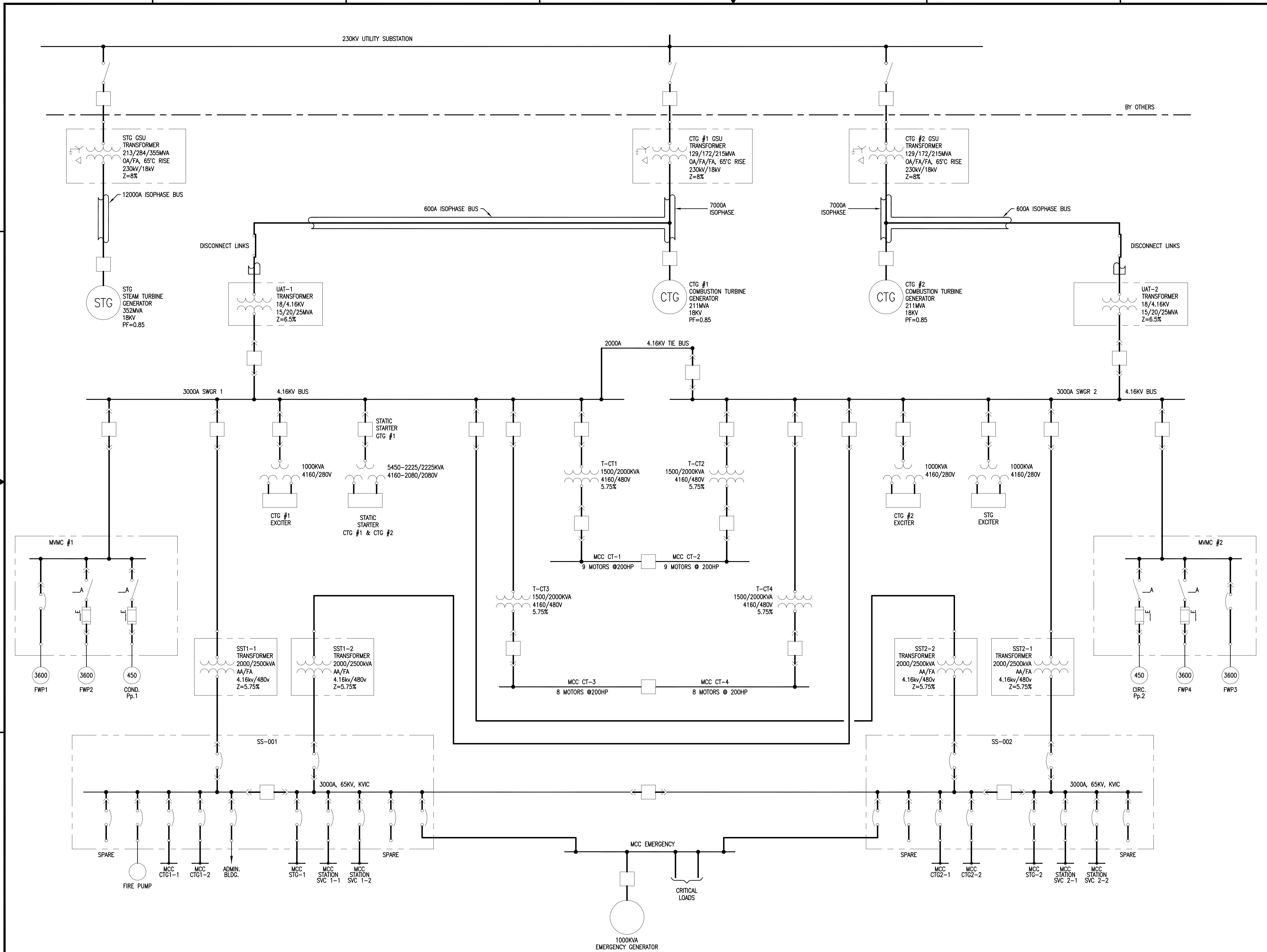
DWG. NO. M-SK-001 REV X

REVIEW SEEN BY: PROCESS PIPING STRUCT MECH ELECT INSTR

1 08027-M-SK-001

APPENDIX B

One Line Diagram



PRELIMINARY

JULY 09, 2008

REV	DATE	STATUS	BY	CHK	P.E.
△		PRELIMINARY			

APPROVED BY:

ENGINEERED BY: T.M. OSBORNE
DRAWN BY: A.M. CANNETTI
DATE: JULY 02 2008
SCALE: NONE
C.O.A.

iea industry and energy associates
27 Pearl Street
Portland, ME 04101

CONT./PROJ. No. 08027

PJM – GE 207FA REFERENCE PLANT

PASTERIS ENERGY, INC.

ONE LINE DIAGRAM

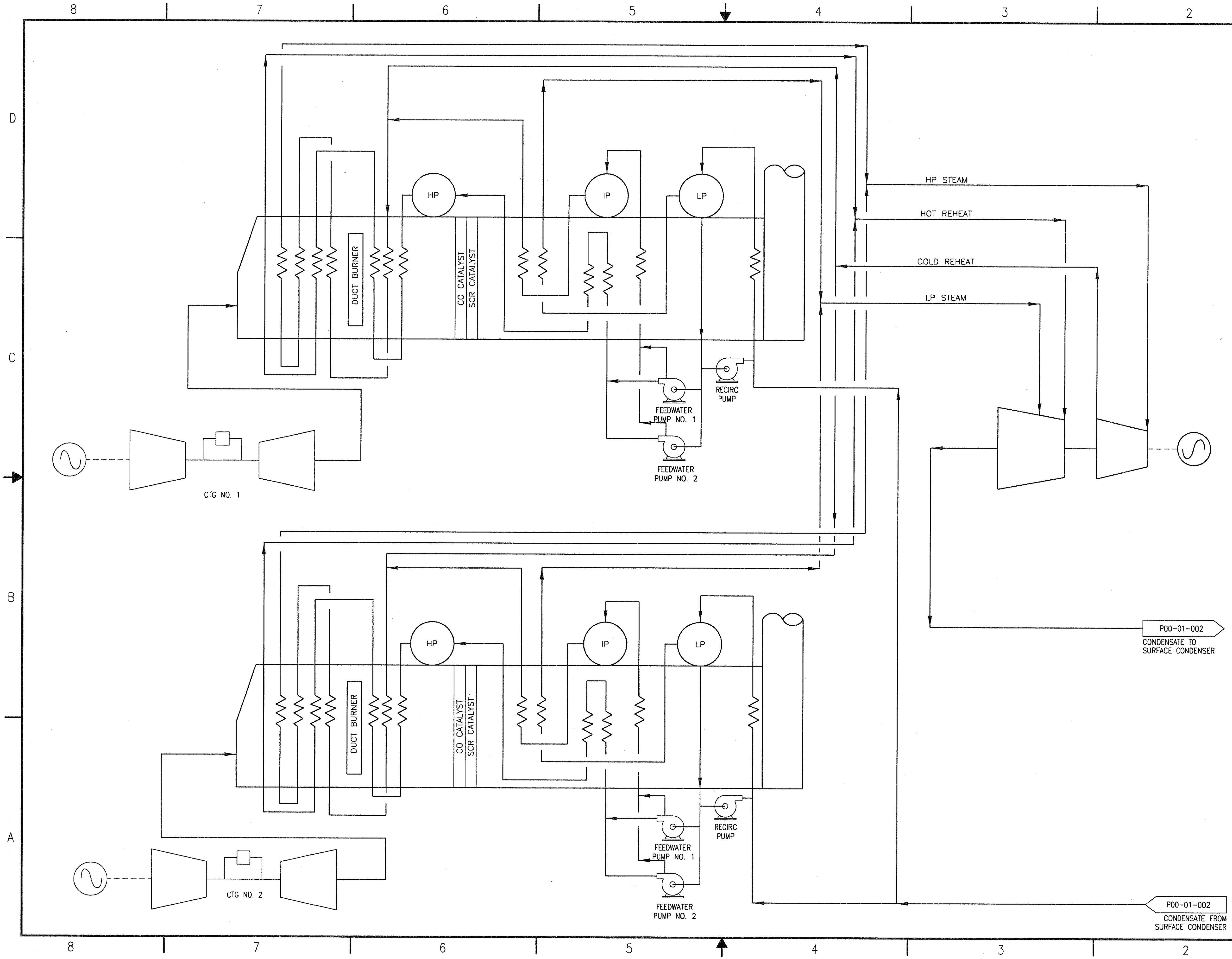
DWG. NO. DWGNO REV △

REVIEW SEEN BY: PROCESS | PIPING | STRUCT | MECH | ELECT | INSTR

FILENAME

APPENDIX C

Process Flow Diagrams



PRELIMINARY

7/9/08

REV	DATE	STATUS	BY	CHK	P.E.

APPROVED BY:

ENGINEERED BY: TAO

DRAWN BY: CMB

DATE: 6/24/08

SCALE: NTS

C.O.A.

industry and energy associates
27 Pearl Street
Portland, ME 04101

CONT./PROJ. No. 08027

PJM – GE 207FA REFERENCE PLANT

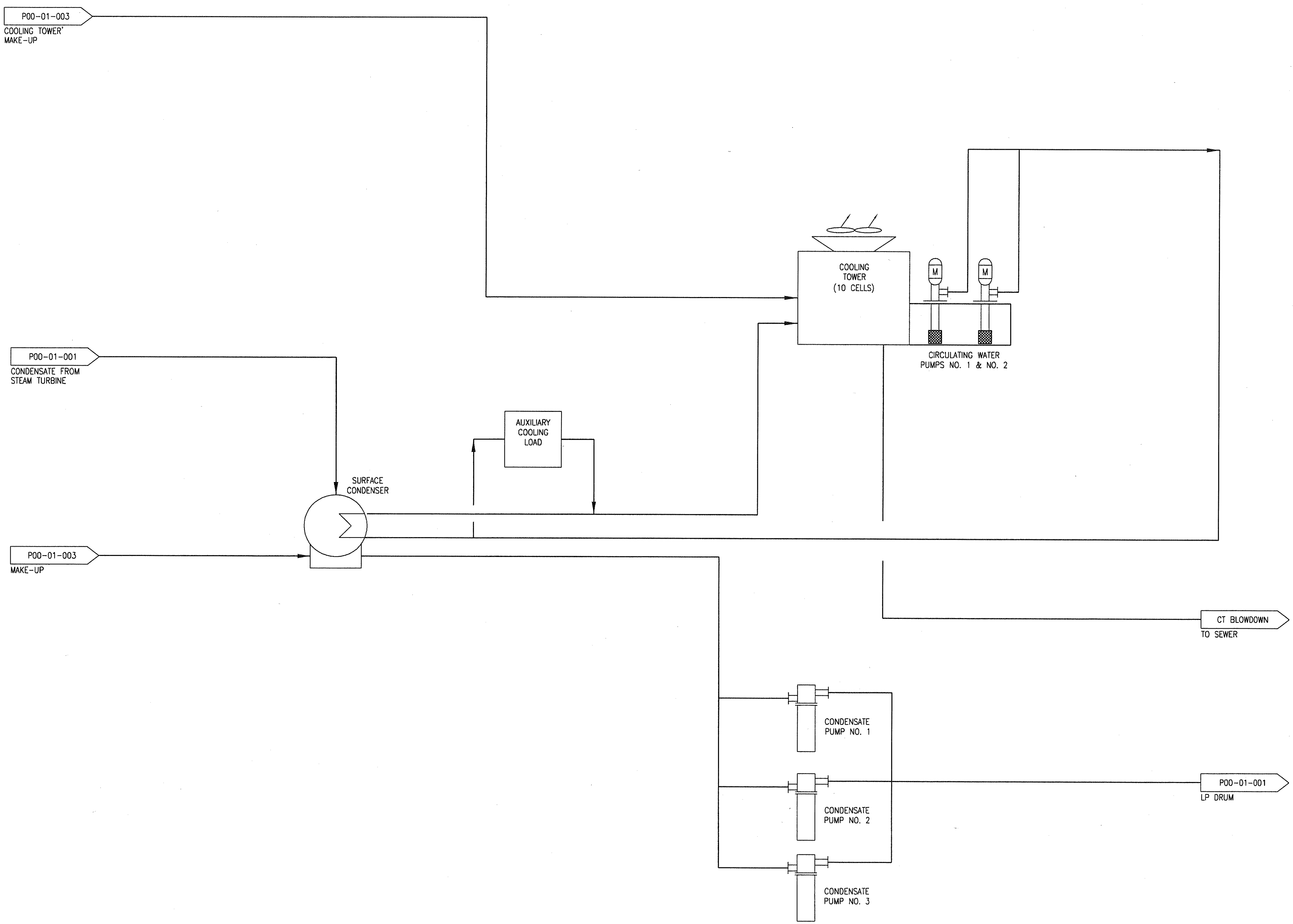
PASTERIS ENERGY, INC.

PROCESS FLOW DIAGRAM
STEAM AND FEEDWATER
SYSTEMS

DWG. NO. P00-01-001 REV X

REVIEW SEEN BY: PROCESS | PIPING | STRUCT | MECH | ELECT | INSTR

08027-P00-01-001.DWG



PRELIMINARY

7/9/08

REV	DATE	STATUS	BY	CHK	P.E.

APPROVED BY:

ENGINEERED BY: TAO
DRAWN BY: CMB
DATE: 6/24/08
SCALE: NTS
C.O.A.

industry and energy associates
27 Pearl Street
Portland, ME 04101

CONT./PROJ. No.
08027

PJM – GE 207FA REFERENCE PLANT

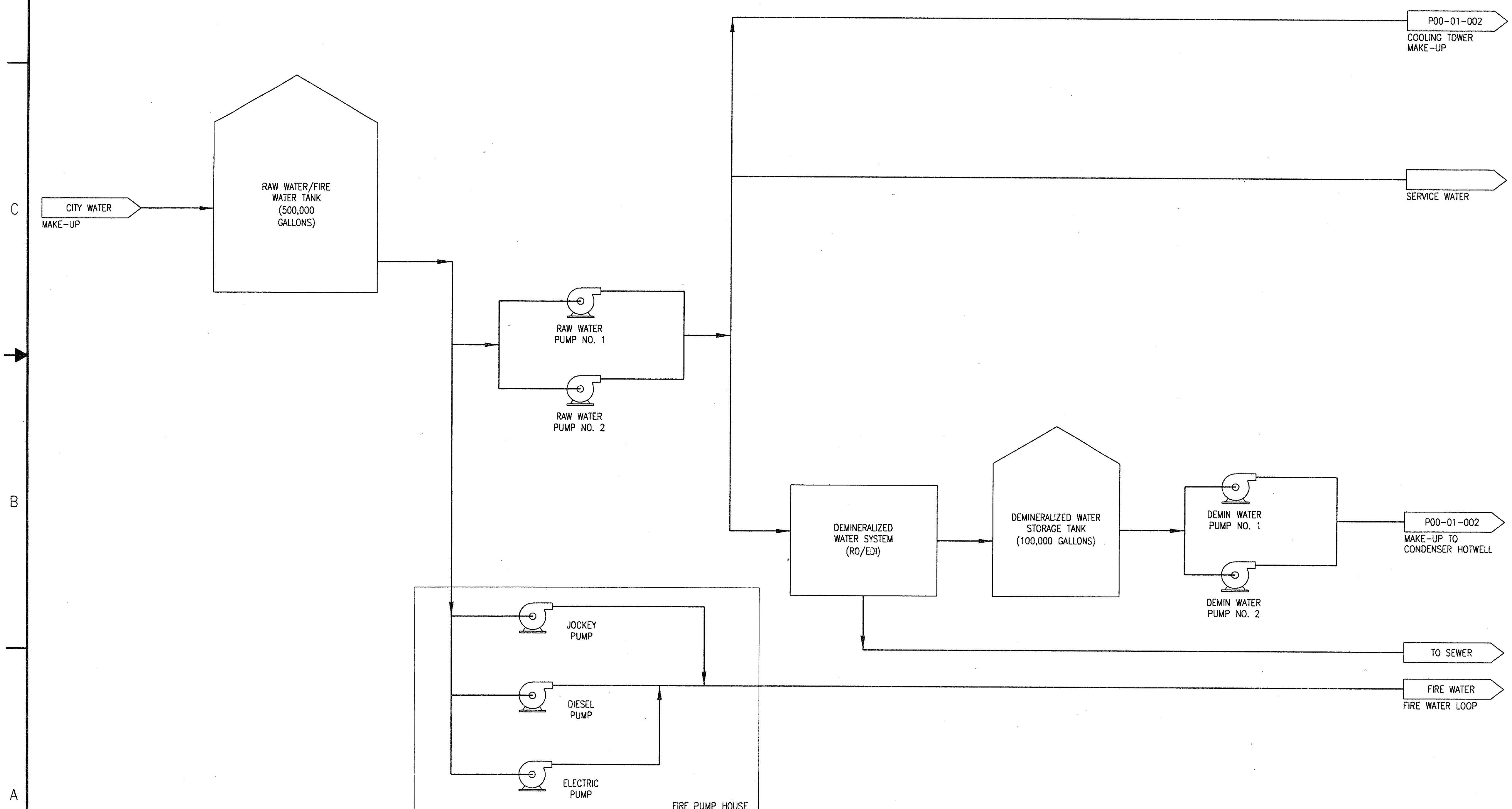
PASTERIS ENERGY, INC.

PROCESS FLOW DIAGRAM
CONDENSATE, CIRC WATER
COOLING WATER SYSTEMS

DWG. NO. P00-01-002 REV A

REVIEW SEEN BY: PROCESS PIPING STRUCT MECH ELECT INSTR

08027-P00-01-001.DWG



PRELIMINARY

7/9/08

REV	DATE	STATUS	BY	CHK	P.E.

APPROVED BY:

ENGINEERED BY: TAO

DRAWN BY: CMB

DATE: 6/24/08

SCALE: NTS

C.O.A.

industry and energy associates
27 Pearl Street
Portland, ME 04101

CONT./PROJ. No. 08027

PJM – GE 207FA REFERENCE PLANT

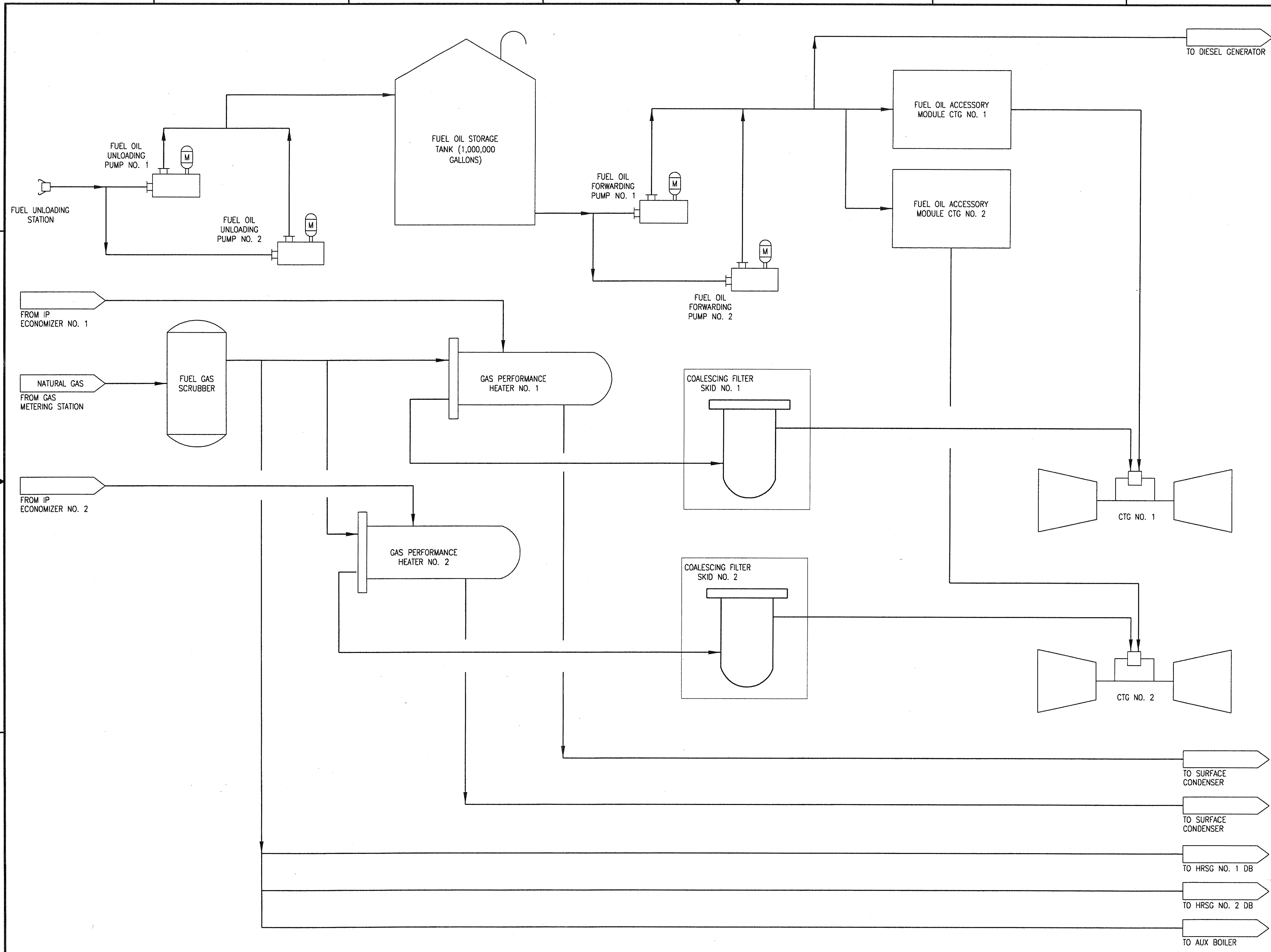
PASTERIS ENERGY, INC.

PROCESS FLOW DIAGRAM
RAW / FIRE & DEMIN
WATER SYSTEMS

DWG. NO. P00–01–003 REV X

REVIEW SEEN BY: PROCESS PIPING STRUCT MECH ELECT INSTR

08027-P00-01-001.DWG



PRELIMINARY
7/9/08

REV	DATE	STATUS	BY	CHK	P.E.

APPROVED BY:

ENGINEERED BY: TAO
DRAWN BY: CMB
DATE: 6/24/08
SCALE: NTS
C.O.A.

industry and energy associates
27 Pearl Street
Portland, ME 04101

CONT./PROJ. No. 08027

PJM – GE 207FA REFERENCE PLANT

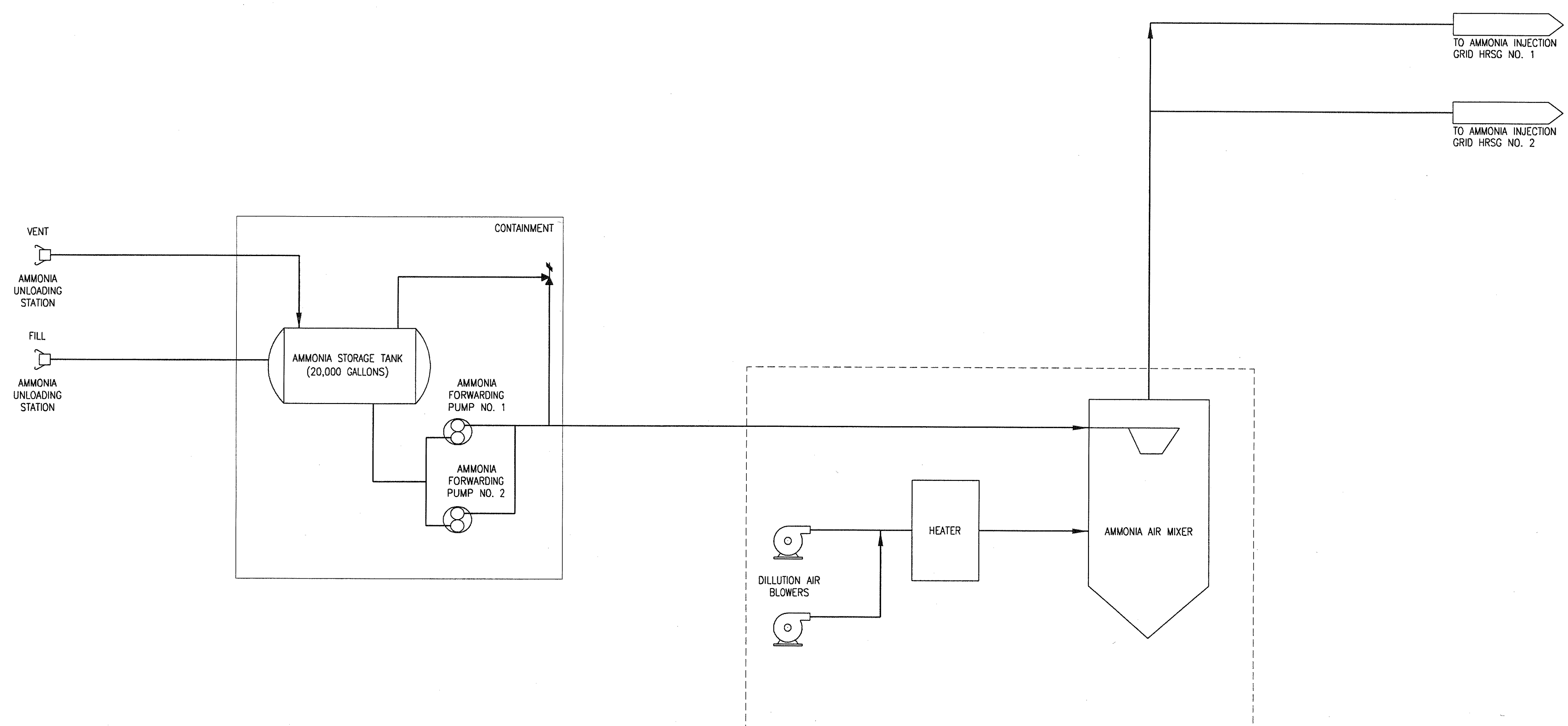
PASTERIS ENERGY, INC.

PROCESS FLOW DIAGRAM
FUEL OIL AND
GAS SYSTEMS

DWG. NO. P00-01-004 REV X

REVIEW SEEN BY: PROCESS PIPING STRUCT MECH ELECT INSTR

1 08027-P00-01-001.DWG



PRELIMINARY
7/9/08

REV	DATE	STATUS	BY	CHK	P.E.

APPROVED BY:

ENGINEERED BY: TAO
DRAWN BY: CMB
DATE: 6/24/08
SCALE: NTS
C.O.A.

industry and energy associates
27 Pearl Street
Portland, ME 04101

CONT./PROJ. No.
08027

PJM – GE 207FA REFERENCE PLANT

PASTERIS ENERGY, INC.

PROCESS FLOW DIAGRAM
AMONNIA SYSTEM

DWG. NO. P00-01-005 REV

REVIEW SEEN BY: PROCESS PIPING STRUCT MECH ELECT INSTR

08027-P00-01-001.DWG

APPENDIX D

Construction Draw Down Financial Schedule

PJM - GE 207FA Reference Plant
Project Drawdown Schedule

Date - Event	% of Total Cost
Month 1 - LNTP	0.1%
Month 2	0.1%
Month 3	0.1%
Month 4 - Power Island Release	6.0%
Month 5	0.2%
Month 6 - FNTP	4.0%
Month 7	0.2%
Month 8	0.2%
Month 9	0.5%
Month 10 - CTG & HRSG Fab Starts	2.0%
Month 11 - BOP Procurement	3.0%
Month 12 - BOP Procurement	3.0%
Month 13 - BOP Procurement	2.0%
Month 14 - BOP Procurement	2.0%
Month 15 - BOP Procurement	2.0%
Month 16 - BOP Procurement	2.0%
Month 17 - BOP Procurement	2.0%
Month 18 - BOP Procurement	2.0%
Month 19 - Mobilization	5.0%
Month 20	5.0%
Month 21	6.0%
Month 22	5.0%
Month 23	5.0%
Month 24	4.0%
Month 25	4.0%
Month 26	4.0%
Month 27	3.0%
Month 28	3.0%
Month 29	3.0%
Month 30	3.0%
Month 31	3.0%
Month 32	3.0%
Month 33	3.0%
Month 34	2.0%
Month 35	2.0%
Month 36 - System Commissioning	0.1%
Month 37	0.1%
Month 38 - Startup Begins	0.1%
Month 39 - Mechanical Completion	0.1%
Month 40	0.1%
Month 41 - Plant Testing	0.1%
Month 42 - Commercial Operation	5.0%
Total	100.0%

APPENDIX E

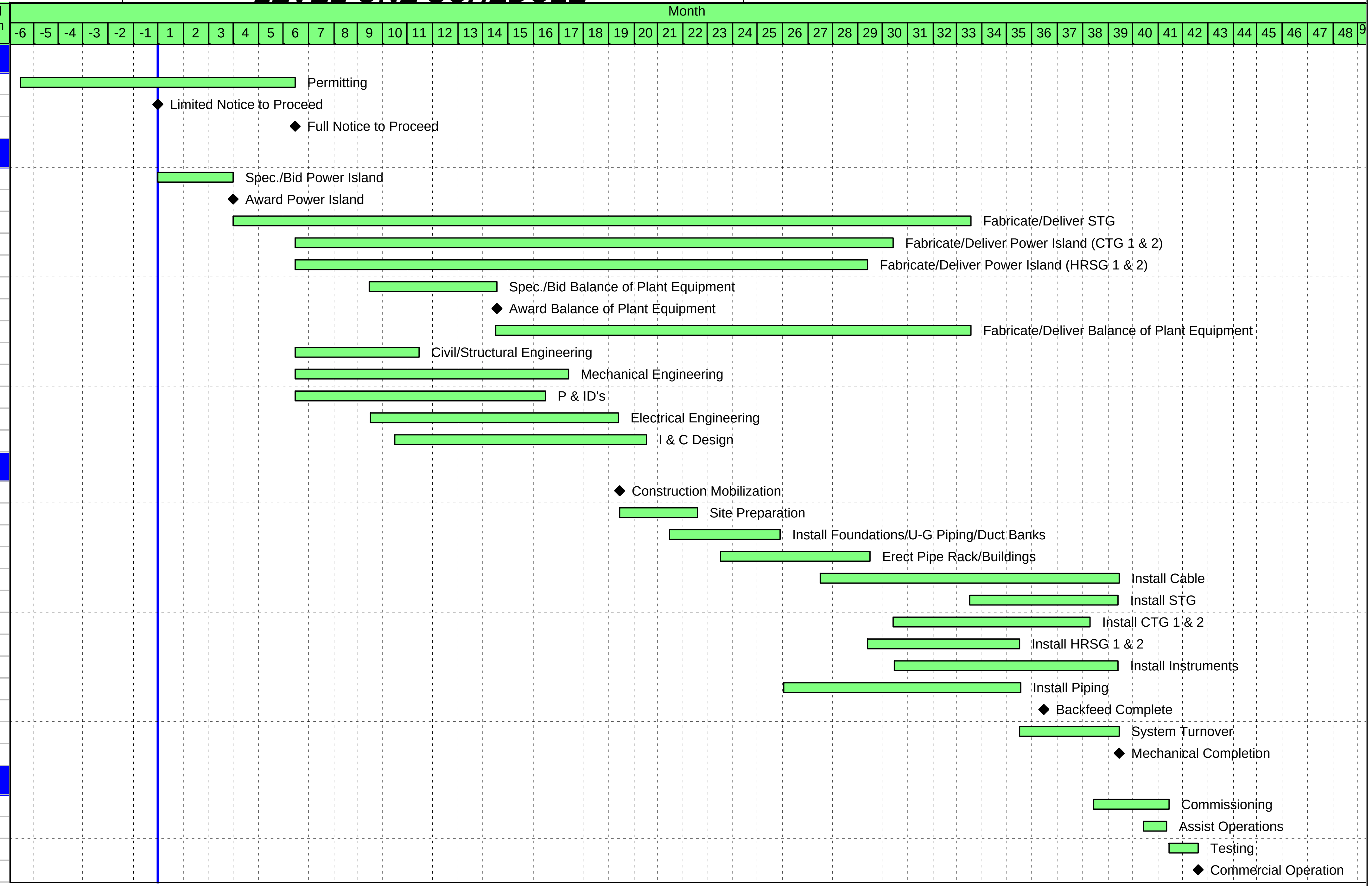
Project Schedule

PJM GE 207FA Reference Plant

LEVEL ONE SCHEDULE

Print Date: 09-Jul-08 10:26

Activity ID	Activity Name	Original Duration
Administration		234
A1005	Permitting	234
A1010	Limited Notice to Proceed	0
A1020	Full Notice to Proceed	0
Engineering and Procurement		683
A1030	Spec./Bid Power Island	64
A1031	Award Power Island	0
A1033	Fabricate/Deliver STG	620
A1036	Fabricate/Deliver Power Island (CTG 1 & 2)	503
A1039	Fabricate/Deliver Power Island (HRSG 1 & 2)	484
A1050	Spec./Bid Balance of Plant Equipment	109
A1052	Award Balance of Plant Equipment	0
A1055	Fabricate/Deliver Balance of Plant Equipment	398
A1150	Civil/Structural Engineering	105
A1160	Mechanical Engineering	232
A1170	P & ID's	213
A1180	Electrical Engineering	208
A1190	I & C Design	211
Construction		422
A1210	Construction Mobilization	0
A1220	Site Preparation	66
A1230	Install Foundations/U-G Piping/Duct Banks	95
A1240	Erect Pipe Rack/Buildings	128
A1245	Install Cable	253
A1248	Install STG	126
A1249	Install CTG 1 & 2	167
A1250	Install HRSG 1 & 2	126
A1275	Install Instruments	188
A1280	Install Piping	200
A1305	Backfeed Complete	0
A1310	System Turnover	85
A1315	Mechanical Completion	0
Start-up		89
A1340	Commissioning	65
A1350	Assist Operations	21
A1360	Testing	24
A1370	Commercial Operation	0



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
◆ Milestone

PJM GE 207FA Reference Plant

industry and energy associates

APPENDIX F

IEA Company Information

An Overview
Of
Industry and Energy Associates, LLC

TABLE OF CONTENTS

1. Introduction

INTRODUCTION

Industry and Energy Associates, LLC (IEA) is a project driven firm that provides engineering, project management, and construction management services for the energy marketplace. IEA has extensive experience in combined cycle, biomass, and renewable energy facilities in the 5 MW to 500 MW range. Using its in-depth project development, detailed design engineering, and management experience, IEA provides innovative, cost effective, and optimal energy solutions.

IEA, with offices in Portland, Maine and Fort Mill, South Carolina, provides the capabilities to meet the total management and engineering needs of its clients. IEA offers big company experience and capabilities in a small package, giving clients personal, one-on-one attention.

IEA personnel are proven professionals with extensive hands-on experience in managing the conceptual design, engineering, construction management, and start-up of complex energy facilities. Through past experience as a part of a large Engineering, Procurement, and Construction (EPC) firm, it has gained the well-rounded knowledge to cover all aspects of a project.

IEA seeks to work as a partner with its clients to create a strong project team. As a team member, IEA works to understand the challenges and needs of its clients. This understanding coupled with IEA's experience will result in the optimal solution to meet the needs of the client and its energy project.

BACKGROUND

IEA was created in July 1997 to take advantage of the engineering and construction capabilities available by the closure of the South Portland, Maine office of a large EPC firm in the power industry. IEA is largely comprised of engineers previously employed by this firm who worked closely as project teams. IEA and its people have a proven track record in project development, permitting, engineering, project management, procurement, construction management, start-up, and testing of power and energy facilities.

In 2000, IEA became part of American Electric Power's (AEP) technical services group, AEP Pro Serv. For the next three years IEA worked on a variety of large and small projects from combined cycle to coal to wind. With the changes in the energy marketplace, AEP decided to divest itself of non-core businesses. This led to the sale of IEA in 2003 to Eakin & Company and Relentless Corp.

IEA continues to provide technical services in the energy field for steam, power, air, and water, to various process facilities, focusing on the food, pulp and paper, electrical generation, marine, petrochemical, gas and oil, and heavy manufacturing industries. As a Relentless Company, IEA is structured to provide a complete range of energy related services to clients ranging from conceptual study to design and permitting to construction, including start-up and commissioning.

IEA personnel have extensive experience in the design and construction of facilities fueled by biomass, coal, gas turbine combined cycle plants, district heating facilities, and gasification projects, as well as wind, waste to energy, and combined heat and power facilities. Its experience and qualifications are demonstrated by its selection to provide complete project services to include; engineering, design, construction, and start-up for various combined cycle plants.

The experience of its employees is strengthened by affiliations with several reputable engineering firms. Through this organizational structure, IEA can offer the total project capabilities of a large engineering firm but with the personal attention provided by a small organization. IEA's management capabilities, procurement experience, and in-depth engineering and design knowledge provides its clients with a total package that can address the needs of a project.

EXPERIENCE

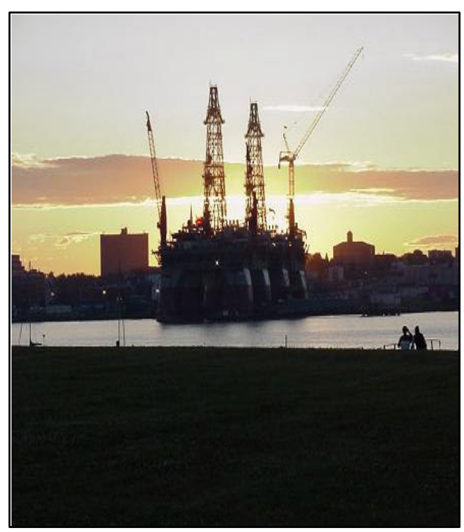
IEA personnel have been involved in the engineering, design, construction, start-up, and testing of numerous waste, biomass, garbage, coal, oil, and natural gas fired steam, power, and cogeneration facilities for industrial and utility clients. IEA employees have designed and managed power and cogeneration facilities ranging in size from 5 MW to 500 MW. These projects were engineered and constructed on a fast track, turnkey, lump sum basis.

IEA personnel were responsible for the procurement of large, capital equipment, whose individual value was in excess of tens of millions of dollars. This procurement responsibility included not only the development of technical specifications but also the negotiation of price, performance, and schedule guarantees, the integration of the vendor drawing and delivery schedule with the overall project schedule, and the negotiation of commercial terms and conditions, including any provisions for liquidated damages. The ability to procure equipment within budget and within the constraints of the overall project schedule is key to the success of the projects.

With this wide range of experience, IEA has the ability to create innovative solutions to complex decisions that power and industrial companies face today.

SERVICES

IEA services can be offered to clients as individual services or as a complete design-build/engineer-procurement-construction package.



- **Detailed Engineering** – IEA offers a full range of engineering and design services covering all disciplines – civil/structural; mechanical; piping; electrical; instrumentation & controls. In addition, IEA has extensive experience in water treatment and waste system design.
- **Procurement** – IEA's extensive experience in purchasing and expediting of equipment is offered as an individual service or as part of an EPC project.
- **Project Management/Construction Management** – Project management and construction services have been implemented with

an integrated control system to maintain accurate scheduling; processing, and cost controls.

- **Project Scheduling and Cost Control** – IEA's project scheduling and cost control services are utilized on all IEA projects and provided as individual services to clients.
- **Start-up; Commissioning and Testing** – IEA provides start-up, commissioning, and testing services. In addition, IEA also performs system turnover and checkout functions as well as conducting equipment, system, and plant testing.
- **Transmission & Distribution** – IEA offers a complete range of design and planning services for virtually any substation or transmission line. IEA has experience up to 500 kV and can provide services from initial studies to planning; detailed design and commissioning either individually or as a complete EPC package.
- **Consulting Services** – IEA offers consulting services to clients that vary from conceptual feasibility studies, permit support, claims consultant, and owner's engineering.
- **Integrated Controls** – IEA has a wide range of expertise in integrated controls systems. This expertise is offered as complete Distributive Control Systems; PLC Systems; Performance Monitoring Applications or Continuous Emission Monitoring Systems (CEMS).

IEA's wide range of services provides clients one stop shopping to meet their energy needs. These services are provided in a variety of industries:

- Utilities (Investor Owned, Municipalities, Co-ops)
- Industrial (Pharmaceuticals, Food Processing)
- Pulp & Paper
- Petrochemical
- District Energy
- Universities
- Semiconductor
- Commercial
- Renewables
- Pollution Control

In a variety of projects:

- Gas Turbine
- Biomass
- Wind
- Waste to Energy
- Combined Heat & Power (CHP)/Cogeneration
- Electrical Transmission & Distribution
- Coal
- Zero Water Discharge
- Distillation
- Gasification
- Equipment Suppliers
- Air Pollution Controls Installation

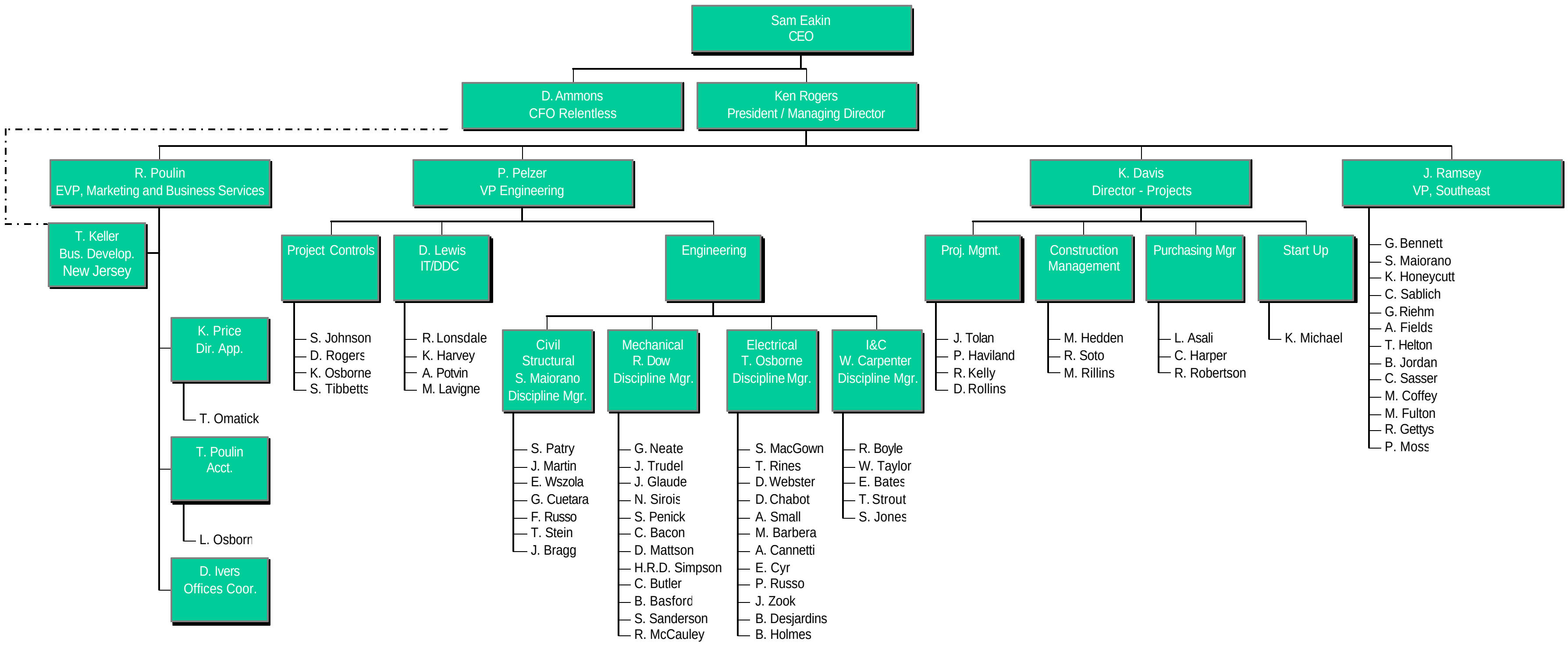
2. History of IEA

Chronological History of IEA

- 1997 - ZURN/NEPCO sale to Enron close Portland office
- 1997 – IEA formed out of NEPCO Portland office
- 1998 - IEA Purchased by Central & Southwest Utilities (CSW) of Dallas, TX
  - Rebuild EPC capabilities
- 2000 - CSW Merged w/ American Electric Power (AEP)
- 2000 - IEA becomes AEP Pro Serv – pursue integrated, EPC projects. Revenues in excess of $400 M
- 2003 - AEP Divestiture of Pro Serv 3rd Party Group
  - Pro Serv 3rd Party ? IEA (again) incorporated into Eakin & Co

3. IEA Organization Chart and Resumes

IEA Organizational Chart



4. Select Project Summary/Experience List

Select Energy Experience List
Industry and Energy Associates, LLC

Year	Client	Description	*Scope Of Services*
1999	Future Energy Resources Corp.	Wood Chip Gasifier Plant DOE Demonstration Project Future Energy Resources Corporation Burlington, Vermont	Engineering, Procurement, and Construction
1999	Conectiv Thermal Systems	District Heating and Cooling Atlantic City Casinos Connective Thermal Systems Atlantic City, New Jersey	Feasibility Study, Plant Performance Optimization Review, Design, Engineering, Construction Management
1999	CSW Energy, Inc.	430 MW Cogeneration Facility Eastex Cogeneration Project Eastex, Texas	Owner's Engineer
1999	Conectiv Thermal Systems	Power Quantity Assessment Study Atlantic City Project Conectiv Thermal Systems Atlantic City, NJ	Engineering Study
1999	The Industrial Company	270 MW Combined Cycle Facility Rathdrum Power Project Rathdrum, Idaho	Engineering, Design and Start-up
1999	Wolverine Power Supply Cooperative	50 MW Simple Cycle Hersey Project Wolverine Power Corporation Hersey, Michigan	Project Management and Engineering Services
1999	CSW Energy, Inc.	120 MW Gas Turbine Facility Expansion Sweeny Cogeneration Project Old Ocean, Texas	Engineer, Procurement, Construction, Start-up and Testing
1999	Conectiv Thermal Systems	District Thermal Energy Plant Conectiv Energy Systems Wilmington, Delaware	Engineering and Design
2000	UAE Power Operations Corp.	180 MW LM6000 Simple Cycle Peaker Lowell Power Expansion Project United American Energy Corporation Lowell, Massachusetts	Project Development, Conceptual Design, Permitting Support
2000	Duke Energy North America	345 kV Substation Duke Energy North America Washington Energy Facility Beverly, Ohio	Engineering, Design, Procurement, Construction and Start-up
2000	DPL Energy	345 kV Substation DPL Energy Montpelier Substation Montpelier, Indiana	Construction & Project Management
2000	Central Sanitary Waste Management	5 MW Generator Installation Pompano Beach Project Central Sanitary Waste Management, Inc. Pompano Beach, Florida	Engineering, Design and Construction Management
2000	Orion Energy	1,800 MW Repowering Project Astoria Station Astoria, New York	Feasibility Study, Conceptual Design and Permitting Support
2000	Central Power & Lime	125 MW GE Turbine Overhaul Central Power & Lime Brooksville, Florida	Supervision, Labor, Tooling & Start-up
2000	Reliant Resources	500 MW Simple Peaker Reliant Resources Ceredo, West Virginia	Engineering, Design, Procurement, Construction and Start-up
2000	CSW Energy, Inc.	138 - 34.5kV Substation and 138kV Transmission Line Trent Wind Farm Trent, Texas	Engineer, Procurement, Start-up and Testing
2000	Competitive Power Ventures	250 MW Combined Cycle Plant Pierce Project Competitive Power Ventures, Inc. Polk County, Florida	Feasibility Study, Conceptual Design, Permitting Support

Year	Client	Description	*Scope Of Services*
2000	Competitive Power Ventures	250 MW Combined Cycle Kingsford Project Competitive Power Ventures, Inc Polk County, Florida	Feasibility Study, Permitting Support
2001	Duke Energy North America	765 kV Substation Duke Energy North America Hanging Rock Station Washington County, Ohio	Project management, engineering, design, equipment procurement, construction management/supervision, test and checkout
2001	City of Garland, Texas	Control System Modernization Orlinger Power Plant Garland Power & Light Garland, Texas	Engineering, Procurement and Control System Integration Services
2001	Competitive Power Ventures	250 MW Combined Cycle Plant Gulf Coast Project Competitive Power Ventures, Inc. Manatee County, Florida	Feasibility Study, Conceptual Design, Permitting Support
2001	Central Maine Power Company	115kV Substation Improvements Sewall Street and Union Street Central Maine Power Corporation Portland, Maine	Engineering, Design and Construction Management
2001	Orange Cogen. Limited Partnership	45,000 GPD Distillation Units Orange Qualified Facility Project Orange Cogeneration, LP Bartow, Florida	Engineering, Design, Procurement, Construction and Start-up
2001	Central Maine Power Company	115kV Substation Lincolnville Project Central Maine Power Corporation Lincolnville, Maine	Engineering, Design and Construction Management
2001	Regional Waste Systems	480 Ton per Day Incineration Plant Waste to Energy Facility Regional Waster Systems Portland, Maine	Engineering and Design
2001	Orion Atlantic, Ltd.	250 MW Combined Cycle Facility Orion Atlantic Project St. Lucia, Florida	Engineering, Design, Procurement and Construction
2001	NRG Energy, Inc.	NRG - York County, PA CC	Feasibility Study, Conceptual Design, Permitting Support
2001	Competitive Power Ventures	550 MW 2X1 Combined Cycle Plant New Britain Project Competitive Power Ventures, Inc	Feasibility Study, Permitting Support
2001	Central Power & Lime	LP Main Oil Pump Rebuild Central Power & Lime Brooksville, Florida	Supervision, Labor, Materials
2001	Duke Energy North America	500 kV Interconnect Facilities Duke Energy North America Fayette PA 1240 MW Peaker Project Fayette, Pennsylvania	Project Management, Engineering, Design, Equipment Procurement, Construction Management/Supervision, Test and Checkout
2001	Allegheny Energy Supply	EPC 345 kV Substation Allegheny Energy Supply Terre Coupee Station New Carlisle, Indiana	Project Management, Engineering, Design, Equipment Procurement, Construction Management/Supervision, Test and Checkout
2001	NRG Energy, Inc	Two Frame 7FA Simple Cycle Peaker Vienna Expansion Project NRG Energy, Inc. Vienna, Maryland	Feasibility Study, Conceptual Design, Permitting Support
2001	Duke Energy North America	500-kV interconnection facilities Duke Energy North America Sandersville Substation Project Sandersville, Georgia	Project Management, Engineering, Design, Equipment Procurement, Construction Management/Supervision, Test and Checkout
2001	Competitive Power Ventures, MD	245 MW Combined Cycle Plant Cana Project Competitive Power Ventures, Inc St. Lucie County, Florida	Feasibility Study, Permitting Support

Year	Client	Description	*Scope Of Services*
2002	AEP Energy Services, Inc.	120 MW Cogeneration Facility Dow Chemical Company Freeport, Texas.	Feasibility Study and Conceptual Design
2002	Aquila Energy	56,100 GPD Distillation Units Lake Qualified Facility Project – LM6000 Plant Lake Cogeneration, LP Umatilla, Florida	Engineering, Design, Procurement, Construction and Start-up
2002	FPL Energy, Wyman LLC	Wyman Station Units 1,2,3 & 4 FPL Energy Yarmouth, Maine	Engineering and Design
2002	Cianbro Corporation	Oil Drilling Rig Amethyst Project Cianbro Corporation Portland, Maine	Engineering, Design and Training
2003	Cianbro Corporation	Co-Gen Installation at Existing Paper Mill Berlin Mill Great Lakes Northern Berlin, NH	Engineering and Design
2003	Cianbro Corporation	115 kV Substation Great Lakes Northern Powersville Road Substation East Millinocket, Maine	Engineering and Design
2003	Great Lakes Northern	Capacitor Bank Installation Great Lakes Northern Millinocket, Maine	Engineering and Design
2004	Ameramex Power Systems, LLC	Ecoenergy / Ameramex Power Systems 1,000 MW Combined Cycle Power Plant with Supporting Facilities	Conceptual Design Study
2004	Pasco Cogen, LTD	51,800 GPD Distillation Units Pasco Cogen - LM6000 Plant Pasco, Florida	Engineering and Design
2004	SNC Lavalin	117 MW LM6000 Combined Cycle Plant Greater Toronto Airports Authority Toronto, Canada	Engineering Services
2004	University of Southern Maine	Cogeneration Plant at the Gorham Campus University of Southern Maine Gorham, ME	Detailed Engineering and Design
2004	American Electric Power	Salvage and Scrap Study Tidd Power Plant Brilliant, Ohio	Feasibility Study
2004	Tillotson Rubber Corporation	Energy Optimization Study Balsam Resort Dixville Notch, NH	Feasibility Study
2005	Sun Coke Company	Coke Oven Power Plant Optimization Haverhill Phase II Haverhill, Ohio	Engineering Services, Optimization, Cost Estimate
2005	Cogentrix	79,200 GPD Distillation Unit Birchwood Cogeneration / Greenhost Inc. King George, Virginia	Detailed Engineering and Design
2005	Cogentrix	2,200 Reverse Osmosis Water Treatment Linden Cogen Plant Linden, New Jersey	Detailed Engineering and Design
2005	Ameresco	Combined Heat & Power Conceptual Design VISN4 (VA Hospitals) Philadelphia, Pittsburgh, Coatsville, Wilkes Barre, PA	Conceptual Engineering, Thermal & Electric Load Analysis
2005	Eastman Chemical	110 MW Steam Turbine Addition Eastman Cogeneration Plant Eastex, Texas	Project Feasibility, Project Cost Estimate
2005	Cogentech	Computer Site Rendering & Plans 50 MW Combined Heat & Power Facility Ontario, Oregon	Conceptual Engineering
2005	Ameresco	3 MW Landfill Gas Reciprocating Engine DSWA Central Project Sandtown, Delaware	Detailed Engineering and Design

Year	Client	Description	*Scope Of Services*
2005	Ameresco	4 MW Landfill Gas Reciprocating Engine DSWA Southern Project Georgetown, Delaware	Detailed Engineering and Design
2005	DCO Energy	2 MW Landfill Gas Reciprocating Engine ACUA Unit 2 Egg Harbor Township, New Jersey	Detailed Engineering and Design
2006	Riverbay Corporation	40 MW Repoweing Combined Cycle Riverbay Cogeneration Bronx, New York	Detailed Engineering and Design Procurement Support
2006	AES	107 MW Coal Fired Boiler Pollution Control Addition Greenidge Project Dresden, New York	Balance of Plant Engineering and Design
2006	Dalkia	Retrofit of Two 120,000 pph Auxiliary Boilers Kendall Station Cambridge, Massachusetts	Detailed Engineering and Design
2006	DCO Energy	2 MW Landfill Gas Reciprocating Engine ACUA Unit 3 Egg Harbor Township, New Jersey	Detailed Engineering and Design
2006	SunCoke Energy	120 Coke Oven Development Gateway Energy Granite City, Illinois	Engineering Services, Optimization, Cost Estimate
2006	American Electric Power	500 MW Combined Cycle J Lamer Stall Project Sheveport, Louisiana	Cycle Optimization
2006	SunCoke Energy	67 MW Coke Oven Power Plant Haverhill Phase II Haverhill, Ohio	Detailed Engineering and Design Procurement Assistance Construction Management & Start -up
2006	General Electric	Various Plant Upgrades Linden Combined Cycle Plant Linden, New Jersey	Detailed Engineering and Design
2006	Cianbro Corporation	Scheduling Services Various Major Construction Project (Bridge, Cement) Northeast	Detailed Scheduling
2006	Congentrix	Arc Flash Studies Ouichita, Southaven, Plains End II, Rathdrum Various States	Engineering
2007	SunCoke Energy	140 Coke Oven & Power Plant Development Indiana Harbor Indiana Harbor, Illinois	Engineering Services, Optimization, Cost Estimate
2007	DCO Energy	Chilled & Hot Water Energy Center Echelon Casino Hotel Las Vegas, Nevada	Detailed Engineering and Design
2007	Cianbro	3 MW Landfill Gas Reciprocating Engine Cassella's Pine Tree Gas to Energy Project Hampden, Maine	Detailed Engineering and Design
2007	Montgomery L'Energia Power	80 MW Combined Cycle Center L'Energia Energy Center Lowell, MA	Detailed Engineering and Design
2007	Nucor	320 Coke Oven Power Plant St. James Project St. James, Louisiana	Engineering Services, Optimization, Cost Estimate
2007	Competitive Power Ventures	500 MW Combined Cycle Plant Walpole Project Walpole, Massachusetts	Conceptual Engineering and Permitting Support
2007	DCO Energy	10 MW Energy Facility Revel Casino Hotel Atlantic City, New Jersey	Detailed Engineering and Design
2007	SunCoke Energy	100 Coke Oven & Power Plant Development Middletown Project Middletown, Ohio	Engineering Services, Optimization, Cost Estimate
2007	Pasco Cogen	Daily Start Study of the 106 MW Plant Pasco Cogen Plant Pasco, Florida	Optimization Study
2007	DCO Energy	1.5 MW Landfill Gas Reciprocating Engine Salem County Alloway, New Jersey	Detailed Engineering and Design

Year	Client	Description	*Scope Of Services*
2008	SunCoke Energy	120 Coke Oven Plant Gateway Energy Granite City, Illinois	Detailed Engineering and Design Procurement Assistance Construction Management & Start-up
2008	UGI Energy	40 MW Coal Plant Repowering Hunlock Creek Project Hunlock Creek, Pennsylvania	Initial Engineering and Design
2008	SunCoke Energy	67 MW Coke Oven Power Plant Middletown Project Middletown, Ohio	Detailed Engineering and Design Procurement Assistance Construction Management & Start-up
2008	Morris Energy	50 MW Simple Cycle Peaker Plant Camden Expansion Project Camden, New York	Initial Engineering and Design
2008	Florida Power & Light	Feedwater Heater Automation Wyman Unit 4 Heater Project Cousin Island, Maine	Detailed Engineering and Design
2008	Tillotson Rubber Corporation	Resort Complex Alternate Energy Study Balsams Energy Side Study Dixville Notch, New Hampshire	Conceptual Engineering
2008	Lockheed Martin	134 MW Solar Thermal Project Renewable Energy Program TBD	Project Management Services
2008	DCO Energy	1.0 MW Landfill Gas Reciprocating Engine SECCRA Project West Grove, Pennsylvania	Detailed Engineering and Design
2008	Graymont	Cement Plant Steam Turbine Evaluation Kiln 7 Power Project Pleasant Gap, Pennsylvania	Engineering Study

Addendum No. 2

Wood Group Power Operations, Inc. O&M Estimates

Wood Group Contractural Solutions
Cost Plus Estimate GE 2 X 7FA Combined Cycle Gas Turbine Facility
PJM Region Facility
Six Year Study
August 1, 2010

Southern NJ	1.0041

ANNUAL O&M					Annual Hours of Operation		4160
Six Year Operations Budget Summary					Fuel Type		Natural Gas
		Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**
Facility Labor Costs		3,149,096	3,161,881	3,161,881	3,161,881	3,161,881	3,161,881
Facility Consumables		171,287	171,287	171,287	171,287	171,287	171,287
Chemicals & Water Treatment		259,115	259,115	259,115	259,115	259,115	259,115
Phone, Postage, Office Supplies, Audits, etc.		133,000	133,000	133,000	133,000	133,000	133,000
EHS Training & Equipment, Travel, & User Groups		129,000	129,000	129,000	129,000	129,000	129,000
Contracted / Outside Services		428,330	428,330	428,330	428,330	428,330	428,330
Miscellaneous Operating Expense		73,060	73,060	73,060	73,060	73,060	73,060
Facility Maintenance & Minor Repair		822,211	822,211	822,211	822,211	822,211	822,211
Fixed Operator Reimbursed Insurance Cost		22,000	22,000	22,000	22,000	22,000	22,000
Freight							
Duties & Nationalization							
Estimated Handling & Administration		201,600	201,600	201,600	201,600	201,600	201,600
Contingency on Fixed Price Contract							
Warranty Credit on First Year (If Applicable)							
Overhead & Management Fee		300,000	300,000	300,000	300,000	300,000	300,000
Foreign Tax Adjustment							
Total Operation & Routine Maintenance Costs		$ 5,688,699	$ 5,701,484	$ 5,701,485	$ 5,701,484	$ 5,701,484	$ 5,701,484

Estimated Initial Inventory	**Total Cost**
Initial Inventory	2,168,750
BOP	625,000
Total Initial Inventory	$ 2,793,750

Pre-Operations & Mobilization - 12 Month Period

		FIXED COSTS	VARIABLE COSTS $/Fired Hr.	TOTAL
Facility Labor Costs Pre-COD		2,613,981		2,613,981
WG Program Implementation & Tech Support Personnel		528,850		528,850
Employee Indoctrination, Training and Qualification		240,000		240,000
Local Administrative Costs (Phone, Fuel, Admin Supplies, etc…)				
Regional & Home Office Support		212,276		212,276
Facility Furniture & Office Equipment		318,300		318,300
Facility Equipment & Specialty Tools		274,000		274,000
CMMS Program		50,000		50,000
Administrative Manual		20,000		20,000
Safety & Environmental Compliance		26,000		26,000
Operations Manual		25,000		25,000
Sub-Total		$ 4,308,407		$ 4,308,407
Handling & Administration	10.0%	92,558		92,558
Overhead & Management Fee		300,000		300,000
Fixed Operator Reimbursed Insurance Costs		22,000		22,000
Freight, Duties, & Nationalization				
Total Mobilization Costs		4,722,963		4,722,964

Wood Group Contractural Solutions
Cost Plus Estimate GE 2 X 7FA Combined Cycle Gas Turbine Facility
PJM Region Facility
Six Year Study
August 1, 2010

Southern NJ	1.0041

		FIXED COSTS	VARIABLE COSTS $/Fired Hr.	TOTAL
1st Year Operation and Routine Maintenance Cost		**$ 5,688,699**		
Annual Hours of Operation		**4160**		
Estimated Dispatch Rate		**47%**		
Labor	23 Employees	2,983,285		2,983,285
General & Administrative Cost for Labor		253,579		253,579
Sub-Total Labor		$ 3,236,864	$ -	3,236,864
Facility Maintenance & Minor Repair		175,440	$ 39.22	895,271
Facility Consumables		76,850	$ 13.50	171,287
Chemicals & Water Treatment		1,330	$ 7.43	259,115
EHS Training & Equipment, Travel, & User Groups		129,000	$ -	129,000
Contracted / Outside Services		235,450	$ 7.81	428,330
Phone, Postage, Office Supplies, Audits, etc.		133,000	$ -	133,000
Fixed Operator Reimbursed Insurance Cost		22,000	$ -	22,000
Sub-Total Maintenance Cost		773,070	$ 304.07	2,038,003
Handling & Administration	8.5%	57,296	$ 25.85	201,600
Overhead & Management Fee		300,000		300,000
TOTAL Overhead & Management Fee with Foreign Tax Adjustment		300,000		300,000
TOTAL Annual Operations & Routine Maintenance Costs		**$ 4,367,230**	**$ 329.92**	**$ 5,776,467**

FACILITY WORKFORCE - ESTIMATED YEAR 1 OPERATIONS					
POSITIONS	Number	WAGE	Base Overtime %	$ Amount of Overtime	Extended
Facility Manager	1	$ 155,000		$ -	$ 155,000.00
Operations & Maintenance Manager	1	$ 120,000		$ -	$ 120,000.00
HSE Manager	1	$ 85,000		$ -	$ 85,000.00
Plant Engineer	1	$ 90,000		$ -	$ 90,000.00
Lead OMT	5	$ 76,960	22%	$ 25,397	$ 511,784.00
Operations & Maintenance Technician	9	$ 68,640	22%	$ 22,651	$ 821,620.80
OMT - Mechanical	2	$ 70,720	18%	$ 19,094	$ 179,628.80
OMC - I&E	2	$ 74,880	18%	$ 20,218	$ 190,195.20
Administrative Assistant	1	$ 47,840	5%	$ 3,588	$ 51,428.00
Position Totals	23				
MANAGEMENT					$ 450,000
OPERATIONS and SUPERVISION					$ 1,754,657
NATIONAL BENEFITS (of ALL Straight Time Wages)				37.67%	$ 778,628
COMBINED SUB-TOTAL (INCLUDING BENEFITS)					$ 2,983,285
G&A (OF ALL STRATIGHT TIME WAGES)				8.50%	$ 253,579
MANAGEMENT					$ 657,765
OPERATIONS and SUPERVISION					$ 2,501,212
				TOTAl	$ 3,158,977

Wood Group Contractural Solutions
Cost Plus Estimate GE 2 X 7FA Combined Cycle Gas Turbine Facility
PJM Region Facility
Six Year Study
August 1, 2010

Southern NJ	1.0041

LABOR COSTS - Facility Mobilization	Annual Salary & OT	Category Total	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Total
Facility Manager	$ 155,000	1	12,917	12,917	12,917	12,917	12,917	12,917	12,917	12,917	12,917	12,917	12,917	12,917	155,000
Operations & Maintenance Manager	$ 120,000	1		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	110,000
HSE Manager	$ 85,000	1		7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	77,917
Plant Engineer	$ 90,000	1		7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	82,500
Lead OMT	$ 102,357	5				42,649	42,649	42,649	42,649	42,649	42,649	42,649	42,649	42,649	383,838
Operations & Maintenance Technician	$ 91,291	9				68,468	68,468	68,468	68,468	68,468	68,468	68,468	68,468	68,468	616,216
OMT - Mechanical	$ 89,814	2				14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	14,969	134,722
OMC - I&E	$ 95,098	2				15,850	15,850	15,850	15,850	15,850	15,850	15,850	15,850	15,850	142,646
Administrative Assistant	$ 51,428	1		4,286	4,286	4,286	4,286	4,286	4,286	4,286	4,286	4,286	4,286	4,286	47,142
DIRECT LABOR COSTS			$ 12,917	$ 41,786	$ 41,786	$ 183,721	$ 183,721	$ 183,721	$ 183,721	$ 183,721	$ 183,721	$ 183,721	$ 183,721	$ 183,721	$ 1,749,981
National Benefits (on ST + ST of OT)		37.67%	$ 4,866	$ 15,741	$ 15,741	$ 69,208	$ 69,208	$ 69,208	$ 69,208	$ 69,208	$ 69,208	$ 69,208	$ 69,208	$ 69,208	$ 659,218
G&A		8.50%	$ 1,512	$ 4,890	$ 4,890	$ 21,499	$ 21,499	$ 21,499	$ 21,499	$ 21,499	$ 21,499	$ 21,499	$ 21,499	$ 21,499	$ 204,782
TOTAL FACILITY LABOR			$ 19,294	$ 62,416	$ 62,416	$ 274,428	$ 274,428	$ 274,428	$ 274,428	$ 274,428	$ 274,428	$ 274,428	$ 274,428	$ 274,428	$ 2,613,981

Addendum No. 3

Pasteris Energy, Inc. Qualifications and Experience

Proven Results

Numerous clients have been successfully supported by **Pasteris Energy, Inc.** A partial listing of clients includes the following companies:

ABB Energy Ventures, Inc.

Air Products and Chemical, Inc.

Atlantic Thermal Systems, Inc.

Aquila Corporation

ArcLight Capital Partners, LLC.

Bioenergy Development Corporation

Brooklyn Navy Yard Cogeneration Partners

Cadillac Renewable Energy, Inc.

Catalyst Energy Corporation

Comision De Regulacion De Energia Y Gas ("CREG") Republica De Colombia

Commonwealth Electric Company

Delta Power Company, LLC.

El Paso Electric Company

Exelon Capital Partners, LLC.

General Electric Capital Corporation

Liberty Power Latin America LP

Monitoring Analytics, LLC

Mobil Power, Inc.

Morris Energy Group, LLC

Ontario Hydro International, Inc.

Olympus Power, LLC.

Panda Energy, Inc.

PEPCO Energy Services, Inc.

PJM Interconnection, LLC

Public Service Electric and Gas

South Jersey Healthcare Systems

South Jersey Port Corporation

Sun Oil Company

Toronto District Heating Corporation

Trigen Energy Corporation

Turbine Air Systems, Inc.

University of Pennsylvania

Valero Refining Corporation

Professionl Services

Pasteris Energy, Inc. is located midway between Philadelphia and New York City operates as a unique energy firm providing services in the following areas:

- Solar Energy Project Development Services
- Project Economic and Financial Evaluation
- Energy System Planning and Management
- Energy Technology Investment Due Diligence
- Combined Heat and Power ("CHP") Development
- GE GateCycle Heat & Material Balances
- Gas Turbine Inlet Air Cooling Evaluation
- Low Temperature Thermal Energy Storage
- Energy Conservation Audits
- Distributed Generation Project Development
- District Heating and Cooling Project Development
- On-line Reverse Auctions for Purchase of Electric & Natural Gas

Pasteris Energy provides domestic and international services to independent power, financial institutions, regulators, governments, district heat & cooling companies, CHP, thermal energy producers, consumers. Services are provided at any phase of a project.

- Services to Independent System Operators (ISO)
- Operations and Asset Management
- Energy Project Appraisal and Feasibility Analysis
- Energy Project Condition Assessment
- Operative Contract Development and Negotiation
- Environmental Permitting Overview
- Energy Project Identification

Client service is **Pasteris Energy's** key objective. **Pasteris Energy** acts as an extension of an organization enhancing the effectiveness of their staff for the short or long term. **Pasteris Energy's** broad experience provides valuable creative input immediately upon request mitigating risk and maximizing the bottom line.

Contact:

Raymond M. Pasteris
Pasteris Energy, Inc.
430 Trend Road
Yardley, Pennsylvania 19067
Phone: 215-736-8170 Fax: 215-736-8171
email: rpasteris@pasterisenergy.com

PASTERIS ENERGY INC.®

Pasteris Energy, Inc. is located between Philadelphia and New York City operates as a unique professional services firm to independent power electric energy markets, district energy and energy consumers.

Raymond M. Pasteris

Raymond M. Pasteris is President of Pasteris Energy, Inc., a professional services firm, which he founded in 1993 to provide project development services to energy producers and consumers worldwide. Mr. Pasteris has over thirty years of domestic and international experience with all phases of engineering, operations and development of energy projects. He has lead energy project development in Argentina, Canada, China, Colombia, the Czech Republic, Peru, Viet Nam, the United Kingdom, as well as the United States.

Previously, from 1990 to 1993, he served as Vice President of Development for United Thermal Corporation, the largest publicly held, independent district heating company in North America. Mr. Pasteris was responsible for project development, contract negotiations, equipment selection and economic evaluations of energy projects. Concurrently he also served as Vice President of Engineering and was responsible for managing corporate engineering, capital budgets and risk management.

From 1986 to 1990 Mr. Pasteris served as General Manager of Cogeneration for Catalyst Energy Corporation a publicly held independent power company, headquartered in New York City. Mr. Pasteris was responsible for all operational, commercial and financial activities of three natural gas and biomass cogeneration projects and one hydroelectric project totaling 51 MW electric capacity, 150 Million BTU per hour of thermal energy and $17 million in annual revenue. Mr. Pasteris also was responsible for facility modifications to improve performance and the management of 42 on site employees.

From 1974 to 1986 Mr. Pasteris served as a senior engineer for Mobil Corporation and developed cogeneration projects for Mobil's operating affiliates worldwide. Activities included field survey of processing facilities to identify cogeneration opportunities, developing power plant configurations to match facility energy requirements for steam and power, performing capital cost estimates, and presenting economic feasibility for executive approval. His efforts resulted in the construction of four cogeneration projects totaling 200 MW at four Mobil refineries.

Mr. Pasteris developed and taught courses in Industrial Water Treatment, for engineers and operators from industries and water utilities in the Chicago area, at Joliet Junior College, Joliet, Illinois.

He is a Licensed Professional Engineer in the State of Illinois and a member of IEEE, ASHRAE and a founding member and Director of the Turbine Inlet Cooling Association (TICA).

Mr. Pasteris received a Bachelor of Science in Chemical Engineering in 1975 from the University of Illinois.

Past Services Provided

Independent Power and Cogeneration Industry

IPP Optimization and Strategic Energy Plan

- Build a GateCycle model of a 400 MW two on one GE Frame 7FA Combined Cycle Plant.
- Evaluated economics of overnight part load operation of the GTG's and STG.
- Evaluated economics of the shutdown of the STG overnight.
- Provided CycleLink offline GateCycle interface for real-time plant optimization by operators.

Cogeneration Project Request for Proposal Response

- Selected technical power cycle configuration to meet industrial steam and power demands.
- Performed cogeneration project heat and material balances.
- Performed project capital cost estimate and soft cost estimates.
- Performed project proforma analysis and determined steam and power price and structure.
- Generated final technical and commercial proposal on behalf of the client.
- Client currently exclusively developing 11 MW power project with host industry start-up in 2002.

Cogeneration Project Feasibility Study

- Selected the technical power cycle configurations to meet district steam demands.
- Performed cogeneration project heat and material balances.
- Performed project EPC cost estimates and soft cost estimates.
- Performed project proforma analysis and determined steam and power price and structure.
- Generated a final technical and commercial report.

Acquisition of Existing Industrial Cogeneration Project

- Performed financial evaluation to establish project value for the acquiring company.
- Performed technical evaluation to determine future project up side potential for client.
- Generated final technical and commercial proposal on behalf of the client.
- Client was selected to the short list of bidders.

Cost of New Entry CT Plant Evaluation for PJM

- Performed technical evaluation to establish project performance, capital and O&M fixed costs.
- Performed financial evaluation to determine fixed revenue requirements of new entry CT plant.
- Conducted numerous presentations to PJM member generators.

Past Services Provided

District Heating and Cooling Industry

EPC Bid Evaluation

- Performed a life cycle economic evaluation of six (6) competitive EPC bids for a 22,000 Ton and 250MMBTU/Hr district heating and cooling plant.
- Evaluation included determining all electric, fuel, water, chemical and O&M expenses.
- Provided a final report ranking the bidders on a project life cycle cost NPV basis.

Washington Convention Center Heating and Cooling Plant RFP Response (50 MMBTU/Hr Heating-10,500 Tons Cooling 4 MW Electric Peak Shave)

- Selected the technical heating and cooling cycle configurations to meet convention center demands.
- Performed heating and cooling project heat and material balances.
- Performed project EPC cost estimates and soft cost estimates.
- Performed project proforma analysis and determined heating and cooing price and structure.
- Assisted in final RFP response preparation and follow up question by Convention Center Authority.
- Client was awarded contract of 20-year energy supply services. Scheduled for 2003 startup.

Services Provided to Governments

Country Regulatory Review Regarding Cogeneration

- Conducted a comprehensive review of current and proposed regulations regarding cogeneration and self-generation for the country of Colombia's Commission for the Regulation of Energy and Gas.
- Submitted a final report of recommendations for implementation into new or modified regulations.

US Trade and Development Agency Funding Proposal

- Developed and submitted proposal to obtain TDA funding for a feasibility study for a cogeneration project in Europe on behalf of our client.
- Approval was obtained for $350,000 of TDA funding to perform the feasibility study.

Oil Refining Industry

Cogeneration Project Proposal Bid Evaluation

- Performed life cycle economic and financial evaluation of seven (7) competitive third party developer bids for a nominal 100 MW cogeneration project.
- Evaluation included a detailed analysis of the electric and steam price and structure expenses for each proposal over the project life.
- Provided a final report ranking the bidders on a project life cycle basis.

Attachment D
Estimates of Net Asset Class Cost of New Entry and MOPR Screens for Combined Cycle and Combustion Turbine Power Plants for Use in May 2011 Base Residual Auction

2011 MOPR Screen for
Combined Cycle Power Plant

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CONE ($/MW-yr ICAP)	$175,250	$154,870	$164,375	$154,870	$154,870
CONE ($/MW-day ICAP)	$480.14	$424.30	$450.34	$424.30	$424.30
Net EAS Revenues ($/MW-yr ICAP)	$104,964	$123,901	$74,346	$84,234	$94,816
Net EAS Revenues ($/MW-day ICAP)	$287.57	$339.45	$203.69	$230.78	$259.77
Net CONE ($/MW-yr ICAP)	$70,286	$30,969	$90,029	$70,636	$60,054
Net CONE ($/MW-day ICAP)	$192.56	$84.85	$246.65	$193.52	$164.53
Net CONE ($/MW-yr UCAP)	$74,971.73	$33,033.60	$96,030.93	$75,345.07	$64,057.60
Net CONE ($/MW-yr UCAP)	$205.40	$90.50	$263.10	$206.42	$175.50
90% Net CONE ($/MW-yr UCAP)	$67,474.56	$29,730.24	$86,427.84	$67,810.56	$57,651.84
90% Net CONE ($/MW-day UCAP)	$184.86	$81.45	$236.79	$185.78	$157.95

CONE Area 1 = PSEG, JCPL, PECO, RECO, DPL
CONE Area 2 = BGE, Pepco
CONE Area 3 = AEP, AP, ComEd, DAY, DLCO
CONE Area 4 = MetEd, PENELEC, PPL
CONE Area 5 = Dominion

Note 1: The Net EAS revenues are equal to the maximum zonal net EAS revenues in each CONE area
Note 2: The CC EAS revenues are calculated using the most recent annual average EFORd available for CC units in PJM
Note 3: UCAP values are derived by dividing the ICAP values by (1-pool wide average EFORd) which for the 2104/15 BRA is 0.0625

2011 MOPR Screen for
Combustion Turbine Power Plant

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CONE ($/MW-yr ICAP)	$138,646	$128,226	$128,226	$128,226	$128,226
CONE ($/MW-day ICAP)	$379.85	$351.30	$351.30	$351.30	$351.30
Net EAS Revenues ($/MW-yr ICAP)	$44,537	$55,106	$26,875	$30,772	$37,853
Net EAS Revenues ($/MW-day ICAP)	$122.02	$150.98	$73.63	$84.31	$103.71
Net CONE ($/MW-yr ICAP)	$94,109	$73,120	$101,351	$97,454	$90,373
Net CONE ($/MW-day ICAP)	$257.83	$200.33	$277.67	$267.00	$247.60
Net CONE ($/MW-yr UCAP)	$100,382.93	$77,994.67	$108,107.73	$103,950.93	$96,397.87
Net CONE ($/MW-yr UCAP)	$275.02	$213.68	$296.19	$284.80	$264.10
90% Net CONE ($/MW-yr UCAP)	$90,344.64	$70,195.20	$97,296.96	$93,555.84	$86,758.08
90% Net CONE ($/MW-day UCAP)	$247.52	$192.32	$266.57	$256.32	$237.69

CONE Area 1 = PSEG, JCPL, PECO, RECO, DPL
CONE Area 2 = BGE, Pepco
CONE Area 3 = AEP, AP, ComEd, DAY, DLCO
CONE Area 4 = MetEd, PENELEC, PPL
CONE Area 5 = Dominion

Note 1: The Net EAS revenues are equal to the maximum zonal net EAS revenues in each CONE area
Note 2: The CONE and Net CONE values come from the planning parameters for the 2014/15 BRA
Note 3: UCAP values are derived by dividing the ICAP values by (1-pool wide average EFORd) which for the 2104/15 BRA is 0.0625