# Exhibit 1

FILED
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**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Application of San Diego Gas & Electric Company (U902E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power. | A.11-05-023<br>(Filed May 19, 2011) |

# PIO PICO ENERGY CENTER NOTICE OF EX PARTE COMMUNICATIONS


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*Attorneys for Pio Pico Energy Center*


Dated: February 8, 2013

**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

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| Application of San Diego Gas & Electric Company (U902E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power. | A.11-05-023<br>(Filed May 19, 2011 |

**PIO PICO ENERGY CENTER NOTICE OF EX PARTE COMMUNICATIONS**

Pursuant to Article 8 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Pio Pico Energy Center ("Pio Pico" or "Project") submits this notice of ex parte communications with Commissioner Mark J. Ferron and his advisor, Michael Colvin, and with Damon Frantz, Advisor to Commission President Michael R. Peevey on February 5, 2013.

Gary Chandler, President of Apex Power Group, LLC and President of Pio Pico; Keith Derman, Partner, Energy Investors Funds ("EIF"), and David L. Huard, Partner, Manatt, Phelps & Phillips, outside counsel to Pico Pico, were in attendance. Both meetings were scheduled at Pico Pico's request and were held at the Commission on 505 Van Ness Avenue in San Francisco. Pio Pico provided a handout, attached hereto as Exhibit A, at both meetings.

At 2:00 pm, Mr. Chandler, Mr. Derman, and Mr. Huard met with Commissioner Ferron and Mr. Colvin for 25 minutes. Mr. Derman provided a brief overview of EIF which is the owner of Pio Pico. He noted that EIF has been a reliable investor in California infrastructure over the last 25 years including investments in transmission, wind, solar, landfill gas, biomass, hydroelectric and natural gas-fired generation. Mr. Derman expressed to Commissioner Ferron that if the Proposed Decision ("PD") or Alternate Proposed Decision ("APD") were not revised to approve Pio Pico, Pio Pico would be terminated and with it a project with no local opposition that offers reliability, jobs, tax base, investment in California and the ability to integrate renewables. He further explained that if the Project cannot close on financing now and start construction as planned, the Project would not likely be able to maintain its Large Generator Interconnection Agreement ("LGIA"), site option, permits and fixed price, date-certain contracts and the Project would be terminated.

Mr. Derman stated that EIF's analysis suggests that there are no other gas-fired peaking projects under development in the San Diego area that could likely be on line before 2020-2022. No peaking projects have submitted applications for approval to the California Energy Commission ("CEC") or are currently in the California Independent System Operator's ("CAISO") queue. Limited Emission Reduction Credit availability in the Air District would make receiving an air permit for a project of similar size difficult and very expensive. As is evidenced by the local opposition to other projects, finding and permitting a site in California is not easy and cannot be taken for granted.

Mr. Derman next stated that the development schedule for any new project will be increased due to new risks for CPUC final approval and it is not prudent for the Commission to assume that a new project can be relied upon to materialize for years. Finally, the price of that capacity could be significantly higher than Pio Pico due to the increased risk profile, timeframe to develop in California, uncertain interconnection costs, higher environmental compliance costs, potential increases in inflation and interest rates and limited competition were any project to actually mature sufficiently.

In addition, Mr. Derman expressed concerns as to the message that the PD and AD sends to developers and investors about investing and doing business in California if the Commission can periodically change its findings as to need; even in the face of local utility, CAISO and CEC support. He stressed that the long term procurement plan was approved by the Commission and with it the request for proposals ("RFP") and that developers, investors, lenders, equipment suppliers and engineering and construction firms are all watching this proceeding very closely. The PD and APD could lead to capital flight and inevitably questions the integrity of reliability in the region (and potentially the State in the longer term) and ultimately leads to significantly higher rates for consumers.

Mr. Derman requested that Commissioner Ferron draft a revised APD which would approve Pio Pico to meet the San Diego area's unquestioned needs at known and very reasonable costs.

At 2:30 p.m. Mr. Chandler, Mr. Derman, and Mr. Huard met with Mr. Franz for approximately 30 minutes. Mr. Derman went through the presentation and discussed the issues as previously discussed in the prior meeting as stated above.

Dated: February 8, 2013

Respectfully submitted,

By: ______________________
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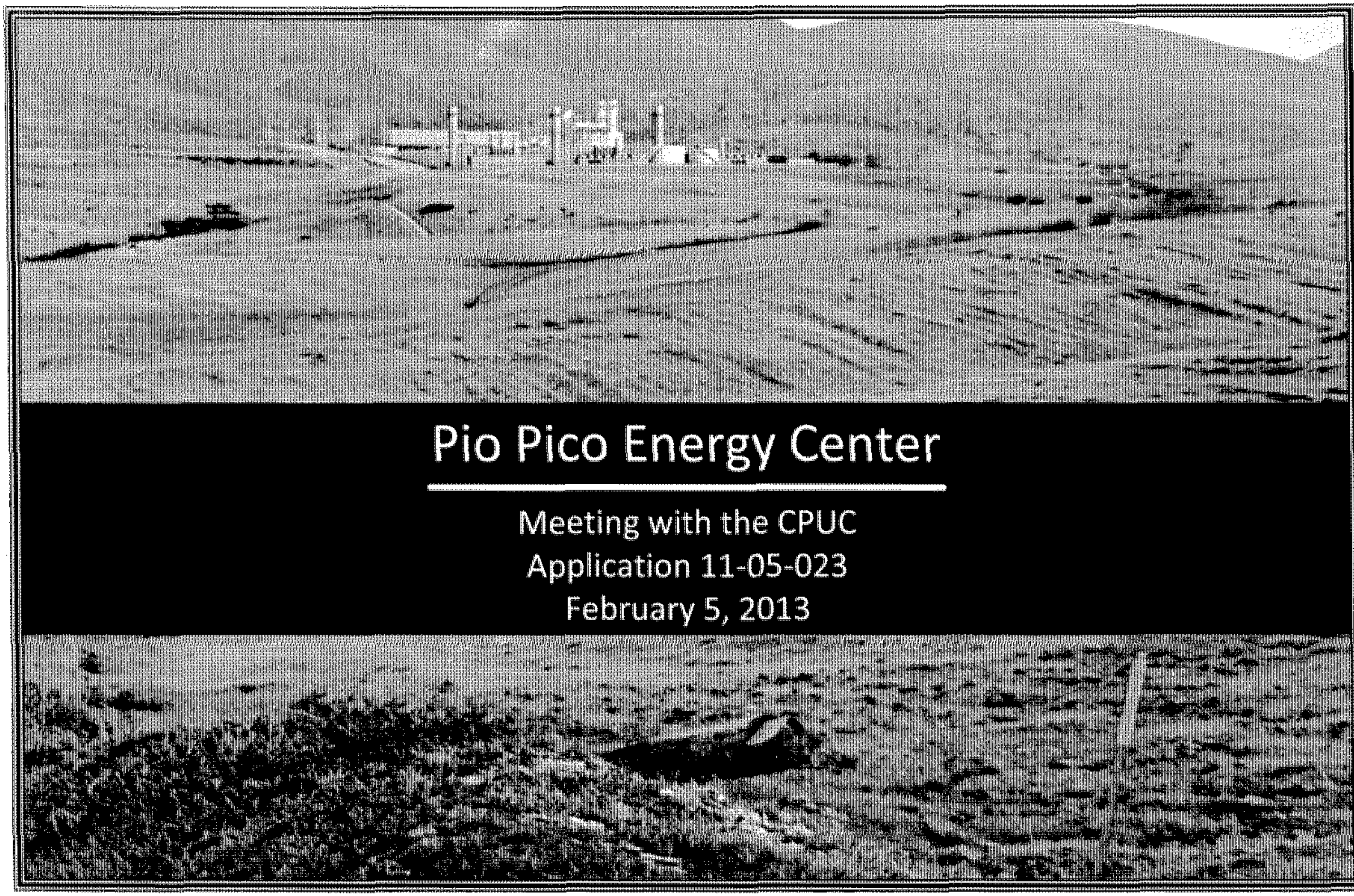
EXHIBIT A



# Pio Pico Energy Center

Meeting with the CPUC
Application 11-05-023
February 5, 2013

ENERGY INVESTORS FUNDS

APEX Power Group, LLC

# Summary Arguments For Pio Pico PPTA Approval

- Pio Pico has been under development for nearly 4 years with millions invested to meet SDG&E required COD
  - ✓ Pio Pico is fully permitted (no local opposition) and shovel-ready
- The PD terminates Pio Pico and with it reliability, new investment, jobs and the potential to integrate renewables
- SDG&E, CAISO and CEC have communicated that local capacity is needed and that Pio Pico should be approved
  - ✓ The South Bay facility was shutdown in 2011, SONGS is still offline, and more plants will be shutdown in the short term that use once through cooling
- There is no gas-fired peaking project in San Diego other than Pio Pico that can realistically be relied on to be in service before 2020 at the earliest
- The implications of the PD/AD (as currently drafted) are severe:
  - ✓ Reliability jeopardized indefinitely with shift of responsibility to the CPUC
  - ✓ Strong and sobering message sent to the independent power community w/r/t development in California
  - ✓ Similarly negative message sent to investors across industries about doing business in California
  - ✓ Development cycle in CA lengthened with significant risk transferred to ratepayers
- <u>What happens if Pio Pico is approved?</u>
  - ✓ Scenario 1: If the experts are right about timing of need, reliability in the short and long term is ensured and costs to ratepayers are reasonable
  - ✓ Scenario 2: If experts are wrong about timing of need, ratepayers pay a few years early for a reasonably priced project, while medium and long term reliability is ensured
- <u>What happens if Pio Pico is not approved?</u>
  - ✓ No guarantee a replacement project ever materializes
  - ✓ Cost of any future capacity that may materialize is highly uncertain (especially if interest rates rise, inflation increases or capacity is needed on an emergency basis)
  - ✓ Highly likely that ratepayers pay significantly more than they would have for Pio Pico and thus give back any savings from not paying for Pio Pico based on the delta in the capacity price

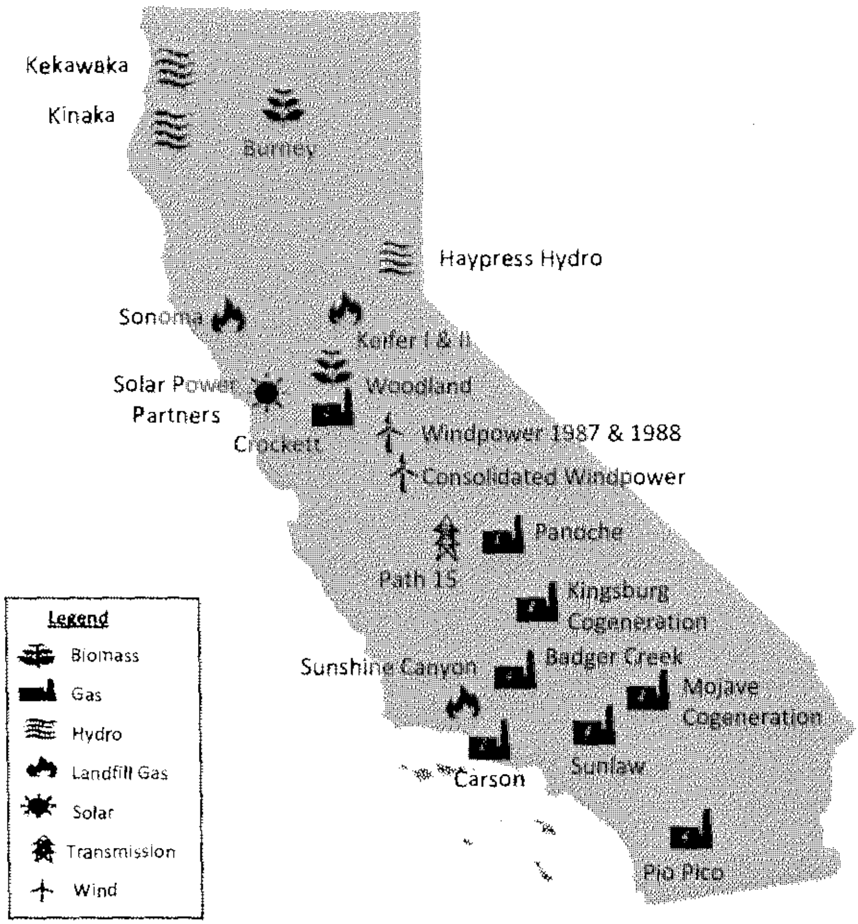
# Sponsor Overview (1 of 2)

- Founded in 1987, EIF was one of the first U.S. private equity fund managers to focus on the independent power industry
- Fully-integrated team of approximately 40 investment, engineering, financial, legal, marketing, and administrative professionals focused on a single line of business
- Offices in San Francisco, Boston and New York
- Historic and continued commitment to California development across fuel types (wind, gas, solar, biomass, hydro, landfill gas and transmission) including notable development and construction of projects such as Path 15, Crockett Cogeneration, Panoche, Sunshine Canyon and Pio Pico
- Experienced investor in all segments of the U.S. power and electric utility sectors with a primary focus on generation and transmission with proven technology
- Since inception, EIF's funds have made more than 100 investments with a combined underlying net asset value exceeding $15 billion
- EIF has raised over $5.0 billion in equity capital and has one of the longest track records among U.S. private equity power fund managers
- EIF's institutional investors have included pension plans (teachers), retirement plans (police and fire), labor unions, endowments and universities including CALPERS and Contra Costa County

**EIF has been a majority investor in 6.3 GW of greenfield generation and transmission projects representing nearly $8 billion of capital costs in the last decade alone**

ENERGY INVESTORS FUNDS

# Sponsor Overview (2 of 2)




**Existing Power Investments**

| Project Name | MW | Fuel Type |
|---|---|---|
| Burney Forest Products | 31 | Biomass |
| Haypress Hydroelectric | 10 | Hydro |
| Kanaka | 1 | Hydro |
| Keifer Landfill Gas I * | 9 | Landfill Gas |
| Keifer Landfill Gas II | 6 | Landfill Gas |
| Kekawaka | 5 | Hydro |
| Panoche Energy Center | 400 | Gas (SC) |
| Pio Pico Energy Center | 300 | Gas (SC) |
| Sonoma County Landfill Plant * | 8 | Landfill Gas |
| Sunshine Canyon | 20 | Landfill Gas |

**Total MW in Existing Investments 790**

**Previous Investments**

| | | |
|---|---|---|
| Badger Creek | 46 | Gas (SC) |
| Carson Cogeneration | 42 | Gas (CC) |
| Consolidated Windpower | 71 | Wind |
| Crockett Cogeneration | 240 | Gas (CC) |
| Kingsburg Cogeneration | 34 | Gas (CC) |
| Mojave Cogeneration | 55 | Gas (CC) |
| Path 15 Upgrade | 1500 | Transmission |
| Solar Power Partners | 30 | Solar |
| Sunlaw | 56 | Gas |
| Windpower 1987 and 1988 | 72 | Wind |
| Woodland | 25 | Biomass |

**Total MW in Previous Investments 2,171**

*Project is operated but not owned by EIF

**EIF has a 25 year track record of supporting generation fueled by conventional and renewable sources as well as energy infrastructure in CA**

ENERGY INVESTORS FUNDS

# Pio Pico Energy Center Overview & Status

- Simple-cycle generation facility using three GE LMS-100 natural gas-fired combustion turbines (~300 MW)
- 20 year Power Purchase and Tolling Agreement ("PPTA") with SDG&E for 100% of capacity and output
- Under development for nearly 4 years in response to RFP
- Owner has invested millions of dollars in order to meet the desired in service date of SDG&E
- Pio Pico will be located on a 10 acre site in Otay Mesa which is already cleared, leveled and zoned accordingly
- Pio Pico has executed all major project contracts including:
  - ✓ Equipment supply agreement with GE
  - ✓ EPC agreement with Kiewit (inclusive of a PLA with $40 million of local labor union payroll)
  - ✓ LGIA with SDG&E/CAISO
- Pio Pico is fully permitted including CEC approvals—there was no local opposition
- Financing is ready to close upon CPUC approval of the PPTA
- Pio Pico is fully capable of performing under the PPTA including delivery date


**Pio Pico is shovel-ready today and offers California employment, new investment, tax-base and low-carbon reliability**

ENERGY INVESTORS FUNDS

# The Current Debate Regarding the PD/AD

- The debate around the PD/AD is generally centered around the timing of the need for new local capacity
  - ✓ Is it 2014 or is it 2018 or is it some time in between?
  - ✓ "Experts (SDG&E, CAISO and CEC) vs. Consumer Advocates"
- Trying to save ratepayers from paying for Pio Pico starting in 2014 will not only put reliability at risk, it will likely drive more significant rate increases in the medium and long term

- <u>What happens if Pio Pico is approved?</u>
  - ✓ Scenario 1: If the experts are right about timing of need, reliability in the short and long term is ensured and costs to ratepayers are reasonable
  - ✓ Scenario 2: If experts are wrong about timing of need, ratepayers pay a few years early for a reasonably priced project, while medium and long term reliability is ensured
- <u>What happens if Pio Pico is not approved?</u>
  - ✓ No guarantee that a replacement project ever materializes
  - ✓ Cost of any future capacity that may materialize is highly uncertain (especially if interest rates rise, inflation increases or capacity is needed on an emergency basis)
  - ✓ Highly likely that ratepayers pay significantly more for a future project than they would have for Pio Pico and thus give back any savings from not paying for Pio Pico based on the delta in the capacity price

**There is just no upside for reliability or the ratepayers in seeing Pio Pico terminated**

# Critical Importance of Pio Pico

- Both SDG&E and CAISO fully demonstrated the need for Pio Pico in the near term
  - ✓ Their commitment and belief of the need has not wavered
  - ✓ CEC Chairman Weisenmiller also supports Pio Pico to meet reliability
- There exists continued uncertainty at SONGS (even if the PD suggests otherwise)
- The nearby 706 MW South Bay Power in nearby Chula Vista was decommissioned in 2011
  - ✓ Thousands of MWs which utilize once-through-cooling are expected to follow suit in the near term
- Pio Pico allows for the integration of renewables (despite factually incorrect arguments in the PD to the contrary) and is consistent with California energy policy
- Developing and permitting new resources in California is more challenging than ever
  - ✓ CAISO process is now up to 3 years long and the time to execute and approve a PPA must dovetail with final deliverability studies to remain in the queue
  - ✓ CEC timeline is 18+ months but it is no longer a "one stop shop" for permits based on the EPA PSD requirement
  - ✓ PSD Permit—lengthy and very challenging process that was not required until 2012 and will make it more difficult to permit power plants in the future
  - ✓ Extremely challenging to locate new generation sources in the State, particularly in the San Diego area
  - ✓ Often strong local opposition as seen at Quail Brush
  - ✓ Very few, if any, sites with electric transmission, gas transmission and water
  - ✓ The sudden new uncertainty as to long term procurement processes in California...

# Limited Other Development in San Diego Area

- There are no other gas-fired projects in the SDG&E service territory in the CAISO queue other than Pio Pico, Quail Brush, Escondido and NRG-Carlsbad (CCGT)
  - ✓ Calpine withdrew from the CAISO queue more than a year ago
- There are no other gas-fired projects in the SDG&E service territory that have CEC approval or have even applied for approval at this time other than (1) Pio Pico, (2) Quail Brush which likely requires rezoning, and (3) NRG-Carlsbad which is a combined cycle
- Very limited emission reduction credit ("ERC") availability in the San Diego APCD registry
  - ✓ Pio Pico's ERCs are derived from shut down of South Bay Power Plant
- Development timeline, as noted in CPUC Proceeding # R12-03-014, is conservatively 7-9 years
  - ✓ San Diego residents better hope the need is not until 2022 (i.e. 2013 + up to 9 years)

**Other than Pio Pico, there are no other peaking projects that can realistically be relied on to be in service before 2020 at the earliest**

# Implications of the PD/AD (1 of 2)

- Pio Pico will be terminated and with it a shovel-ready project that offered low cost reliability, jobs, investment and the ability to integrate renewables
  - ✓ EPC will be cancelled and with it goes the firm commitments on price
  - ✓ Equipment resold or utilized at another project
  - ✓ CAISO LGIA immediately in jeopardy; likely have to restart process
  - ✓ Permit maintenance uncertainty
  - ✓ Site option terminated

- Reliability, in Southern California, despite the strident objections from SDG&E, CAISO and the CEC, will be put in jeopardy
  - ✓ The PD's rejection of SDG&E's and CAISO's testimony puts the blame squarely on the CPUC if there are outages over the next decade
  - ✓ Very strong possibility that the cost of any new plant will be significantly greater than Pio Pico
  - ✓ No guarantee that a new plant will be available in 2018-2020 and such risk, which is always considerable, only increases as a result of this PD

✓ The PD when compared to the PD in proceeding # R12-03-014 highlights inconsistency in energy policy and decision-making at the CPUC

# Implications of the PD/AD (2 of 2)

- The PD sends a message to the independent power community that is nothing short of **chilling** with respect to future power development in California
  - ✓ The CPUC authorized the RFO in the first place and now (after a 20+ month review process) has arbitrarily changed its mind as to the need
  - ✓ The PD has the potential to set a very dangerous precedent to make all future PPAs subject to later review of need even after projects receive all approvals and are ready to construct
  - ✓ The PD recommends a new RFO with the caveat that future CPUC approval "will take into consideration material intervening events and circumstances"
  - ✓ Be assured that developers, EPC firms and equipment suppliers are watching this proceeding **VERY** closely
- The PD sends a message to investors (energy and otherwise) about the vagaries of deploying capital in California
- The PD further lengthens an already protracted development schedule because capital cannot be reasonably deployed with the CPUC contract approval risk over-hang
- The PD may not just lengthen the development schedule, it may actually make it impossible
  - ✓ No developer can or will commit to a fixed price contract and then successfully lock in its capital costs while waiting for the CPUC to decide if its long term forecast or policy ambitions have remained the same

# Project Checklist

- LTPP Need ✓
- RFO ✓
- PPA ✓
- LGIA ✓
- EPC and Project Labor Agreement ✓
- Equipment Supply ✓
- CEC Permit ✓
- PSD Permit ✓
- Financing ✓
- Shovel Ready ✓
- CPUC Final Authorization ?

ENERGY INVESTORS FUNDS

# Exhibit 2

sierra
research

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Sacramento, CA 95811
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April 13, 2012

Mr. Gerardo Rios
Chief, Permits Office
U.S. EPA Region 9
75 Hawthorne Street
San Francisco, CA 94105

Subject: Pio Pico Energy Center PSD Permit Application
Response to Supplemental Information Request

Dear Mr. Rios:

As requested in your March 21, 2012 email request, we are submitting the additional information set forth below on behalf of Applicant Pio Pico Energy Center LLC.

## 10-Minute Startup Requirement

*Comment: You agreed to provide an explanation of the need for a 10 minute turbine start-up time, and why a longer startup time, e.g., 30 minutes, would not be consistent with the operational needs of the project.*

First, it is important to clear up a misunderstanding about the startup time for the current generation of "fast start" combined-cycle units. There are no combined cycle configurations in the size range needed for this project that can start up and reach full rated power in 30 minutes.[1] For a 300 MW combined cycle unit, an output of only 180-200 MW can be achieved within this 30 minute time period. It takes a considerably longer period of time for a combined cycle unit to reach full load under combined cycle operation (and corresponding efficiency).

Under hot start conditions, it can take up to 2 hours for a combined cycle unit to reach full power production. Under cold start conditions, up to 3 ½ hours are required to achieve full load combined cycle output. Because the purpose of the comparison between simple cycle and combined cycle turbine performance is to evaluate whether a combined cycle unit is capable of meeting the performance requirements of the project, the more appropriate question is "why a longer startup time (e.g., 125 minutes) would not be consistent with the operational need of the project."

[1] Both Siemens and GE have developed "flexible efficiency" combined cycle units capable of reaching full gas turbine capacity in 30 minutes from a hot start. However, these units are rated at over 500 MW; and under cold start conditions, the time to full load is considerably longer than 30 minutes. For a peaking facility such as PPEC, fast cold start response is an important feature.

No single power production technology is capable of meeting all of the needs of a power production system. In general, renewable resources produce relatively low greenhouse gas emissions, but are not reliable or available at all times. Baseload technologies provide steady, reliable, and efficient power, but cannot react quickly to changes in load or supply. Enough generation must be distributed in order to balance the generation and load demands of the electric distribution systems. The power production system uses different power production technologies so that the system, as a whole, is capable of meeting the widely varying demands placed on it, without grid instability or possible interruption of service.

EPA has recognized the distinction between baseload, intermediate, and peaking power production, and the fact that certain technologies are not suited for all uses. Specifically, EPA has recognized that combined cycle facilities are well-suited for baseload and intermediate power production, due to their efficiency. However, the relatively high capital costs and relatively slow response times of combined cycle facilities makes them unsuited for use as peaking production units. Power grids need both in their mix of resources.[2] For peaking service, a delay of an hour or more from dispatch to full load is not acceptable.

PPEC was designed to meet SDG&E's stated need for peaking/intermediate capability (see Product 2 of the attached letter from SDG&E). It is important to understand the context of the RFO in order to interpret the requirements. First, at the time that the RFO was published (and, indeed, at this time as well) combined cycle plants were not considered candidates for peaking operation. Second, the anticipated heat rate of 10,500 Btu/kWh in the RFO is consistent with an expectation that simple cycle technology would be proposed. Finally, the requirement that proposals should provide "flexible resources that are capable of providing regulation" and that proposals capable of "quick start operations" would be ranked higher both rule out technology with a long startup cycle. All three bids that were accepted by SDG&E in response to the RFO were either simple cycle combustion turbines or reciprocating engines, all with extremely fast response and startup times. This provides clear evidence that a combined cycle alternative to PPEC would not have been feasible as a practical matter, as it would not have been selected to receive a contract by SDG&E.

PPEC is designed to operate not more than 4,000 hours per year, and to cycle several times a day in response to sudden shifts in demand. A combined cycle unit operating in this fashion would a) spend much of its operating time ramping up or ramping down the steam turbine, thereby not achieving the expected combined cycle efficiency; and b) incur significant maintenance costs as a result.

Because a combined cycle unit would constitute a fundamental redesign of the project, and because use of currently available combined cycle technology would not meet the legitimate objectives of the project, combined cycle technology was eliminated as technically infeasible at Step 2 of the Top-Down BACT analysis.

[2] EPA, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (March 27, 2012). "The EPA is not including stationary simple cycle turbines in this rule because they generally operate differently than the other units covered by today's rule. The units covered by today's rule are generally used to serve baseload or intermediate demand, while simple cycle turbines are generally used much less often (and thus have lower GHG emissions) and are generally used to meet peak demand rather than base or intermediate load requirements."

## Cost Data

*Comment: You agreed to provide cost data that compares construction and annual operating costs of your proposed simple cycle plant with a hypothetical combined cycle plant of similar capacity.*

**Response:** Applicant retained E3 Consulting, LLC, to evaluate the costs to build and operate a nominal 300 MW power generation facility using three different generation technology options. The following three options were evaluated:

- GE LMS100PA, three units in simple-cycle configuration;
- GE Frame 7FA.04 Fast Start in 1x1 combined-cycle configuration; and
- Siemens SGT 5000F Flex 10 1x1 combined-cycle configuration.

The basis for the analysis is provided in Table 1. The results of cost analysis are summarized in Table 2. Details of the analysis are provided in the attached letter from E3 Consulting.

Applicant has evaluated the emissions associated with each of the options for which cost estimates were developed. The same basis used for cost calculations was used for emission calculations. Emissions are summarized in Table 3. This table shows that the GE FS Combined Cycle unit would have higher GHG emissions than the simple cycle configuration proposed for Pio Pico for the specific operating scenario expected for PPEC. This occurs because the lengthy startup cycle results in significantly more hours of startup time, with significantly more fuel consumption, during the 500 starts per year that PPEC is required to offer. The GE FS CC configuration is therefore eliminated as a candidate for BACT for GHG for this project.

Details of the GHG calculations are presented in Tables 4 through 7.

**Table 1A Operating Scenario**

| | Pio Pico | GE FS CC | Siemens FS CC |
|---|---|---|---|
| COLD STARTS | | | |
| Number of cold startups per year | 500 | 52 | 52 |
| Duration of cold startup (total, incl. SC + CC) (hrs/start) | 0.2 | 3.5 | 2.08 |
| Duration of elevated emissions during cold startup (hrs/start) | 0.5 | 0.75 | 0.20 |
| Duration of normal emissions during cold startup (hrs/start) | 0.0 | 2.75 | 1.88 |
| Hours of elevated emissions during cold startups per year (hrs/yr) | 250.0 | 39.0 | 10.4 |
| Hours of normal emissions during cold startup (hrs/yr) | 0.0 | 143 | 97.9 |
| HOT/WARM STARTS | | | |
| Number of hot/warm startups per year | inc | 448 | 448 |
| Duration of hot/warm startup (total, incl. SC + CC) | inc | 2 | 1 |
| Duration of elevated emissions during hot/warm startup (hrs/start) | inc | 0.23 | 0.2 |
| Duration of normal emissions during hot/warm startup (hrs/start) | inc | 1.77 | 0.75 |
| Hours of elevated emissions during hot/warm startups per year (hrs/yr) | inc | 104.5 | 89.6 |
| Hours of normal emissions during hot/warm startups per year (hrs/yr) | inc | 791.5 | 336 |
| SHUTDOWNS | | | |
| Number of shutdowns per year | 500 | 500 | 500 |
| Duration of shutdown (total, incl SC + CC) | 0.2 | 1 | 1 |
| Duration of elevated emissions during shutdown (hrs) | 0.2 | 0.5 | 0.5 |
| Hours of elevated emissions during shutdown per year (hrs/yr) | 83.3 | 250 | 250 |
| Duration of normal emissions during shutdown (hrs) | 0.0 | 0.5 | 0.5 |
| Hours of normal emissions during shutdown per year (hrs/yr) | 0.0 | 250 | 250 |
| ANNUAL OPERATIONS | | | |
| Total operating hours per year (hrs/yr) | 4167 | 5578 | 5034 |
| Hours of elevated startup/shutdown emissions per year (hrs/yr) | 333 | 394 | 350 |
| Hours of normal startup/shutdown emissions per year (hrs/yr) | 0 | 1184 | 684 |
| Hours of startup operation per year | 83 | 1078 | 534 |
| Hours of shutdown operation per year | 83 | 500 | 500 |
| Hours gas turbine baseload operation per year (hrs/yr) | 4000 | 4000 | 4000 |

**Table 1B Predicted Heat and Power Rates**

| GE LMS100PA SC (Pio Pico Energy Center) | Heat Input HHV | Turbine Output MW | Heat Rate, Btu/kWh |
|---|---|---|---|
| Full load, ~ISO conditions (63 F) | 903 | 103.3 | 8738 |
| Min load, ~ISO conditions | 546 | 51.6 | 10576 |

| GE Frame 7FA.04 (Fast Start) 1x1 CC (from Oakley Generating Station) | Heat Input HHV | Turbine Output MW | Heat Rate, Btu/kWh |
|---|---|---|---|
| GT only, full load, ISO conditions | 2102 | 213 | 9869 |
| GT only, min load, ISO conditions | 1339 | 104 | 12829 |
| CC, full load (net heat rate from AFC) | 2102 | 312 | 6752 |
| Average, SC to CC full load | 2102 | 263 | 8310 |

Notes:

1. Includes evaporative cooling and ACC
2. Cold startup: 45 min to SC full + 2 hr 45 min to CC full (total start time from McLucas/Radback 10/21/10 email to BAAQMD); warm/hot start: 14 min to SC full + 1 hr 46 min SC to CC full (total start time from McLucas/Radback 10/21/10 email to BAAQMD); shutdown: 30 min CC full to SC full + 30 min SC full to off
3. Assume 5000 hours of operation per year for aux boiler, including 500 startups/shutdowns

(per FDOC, aux boiler operates when turbine is down plus during turbine startup/shutdown)

50.6 MMBtu/hr steady state

25.3 MMBtu/hr startup/shutdown

| Siemens SGT6 5000F (Flex 10) 1x1 CC (from Carlsbad Energy Center Project) | Heat Input HHV | Turbine Output MW | Heat Rate, Btu/kWh |
|---|---|---|---|
| GT only, full load, ISO conditions | 2000 | 208 | 9615 |
| GT only, min load, ISO conditions | 1227 | 104 | 11798 |
| CC, full load | 2000 | 279 | 7168 |
| Average, SC to CC full load | 2000 | 244 | 8392 |

Notes:

1. Includes evaporative cooling and ACC; heat input at ISO conditions without PAG
2. Full load CC turbine output from GHG Table 2, p. 6.1-13, of the RPMPD for Carlsbad Energy Center
3. Cold startup: 12 min to SC full + 113 min to CC full (from Siemens startup curves); warm/hot start: 12 min to SC full + 45 min SC to CC full (from Siemens startup curves, avg of hot and warm ST times); shutdown: 30 min CC full to SC full + 30 min SC full to off
4. Assume Siemens CC utilizes same evaporative cooler as GE CC

**Table 2 Turbine Capital and Operating Costs**

| Primary Technology | Configuration/ Cycle | Net Output | | Capital Cost | Fixed O&M Cost | Variable O&M (non major) | Major Maintenance | Total Maintenance | Total Maintenance |
|---|---|---|---|---|---|---|---|---|---|
| | | MW | MWH/yr | $/kW | $/kw-yr | $/MWH | $/MWH | $/MWH | $MM/year |
| **LMS100PA-SAC** | 3x0 SC | 310 | 1,265,400 | 829 | 15.3 | 0.91 | 2.09 | $3.015 | $3.82 |
| **GE 7FA.05** | 1x1 CC Fast Start | 312 | 1,599,996 | 1029 | 16.1 | 0.85 | 2.35 | $3.216 | $5.15 |
| **Siemens SGT6-5000F** | 1x1 CC Flex 10 | 279 | 1,318,938 | 1153 | 16.1 | 0.85 | 4.56 | $5.426 | $7.16 |

**Table 3 Emissions**

| | NOx | | | SOx | | | CO | | | VOC | | | PM10 | | | GHGs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Max lb/hr | Max lb/day | Total tpy | Max lb/hr | Max lb/day | Total tpy | Max lb/hr | Max lb/day | Total tpy | Max lb/hr | Max lb/day | Total tpy | Max lb/hr | Max | Total tpy | CO2e metric tpy |
| **LMS100 totals** | 79.8 | 898.2 | 68.4 | 5.3 | 141.4 | 3.9 | 160.9 | 1320.6 | 94.5 | 19.8 | 268.0 | 20.2 | 17.2 | 433.8 | 35.8 | 608,547 |
| **7FA totals** | 97.6 | 496.3 | 49.3 | 6.0 | 136.9 | 5.5 | 361.3 | 814.0 | 54.5 | 67.4 | 220.3 | 19.4 | 8.8 | 210.0 | 23.9 | 625,385 |
| **SGT6-5000F totals** | 69.2 | 426.9 | 42.0 | 4.2 | 94.4 | 3.4 | 545.0 | 913.4 | 63.1 | 33.1 | 120.2 | 11.7 | 10.2 | 243.8 | 25.3 | 521,540 |
| **Difference, LMS 100 vs 7FA** | **-17.8** | **401.9** | **19.1** | **-0.7** | **4.5** | **-1.6** | **-200.4** | **506.6** | **40.0** | **-47.6** | **47.6** | **0.8** | **8.4** | **223.8** | **11.9** | **-16,838** |
| **Difference, LMS 100 vs SGT6** | **10.6** | **471.3** | **26.4** | **1.1** | **47.1** | **0.5** | **-384.1** | **407.2** | **31.4** | **-13.3** | **147.8** | **8.5** | **7.0** | **190.0** | **10.5** | **87,007** |

**Table 4 Natural Gas Combustion GHG Emission Rates**

| Pollutant | CO2 (2) | CH4 (3) | N2O (3) | SF6 |
|---|---|---|---|---|
| **Emission Factors, kg/MMBtu** | 53.020 | 1.00E-03 | 1.00E-04 | n/a |
| **Global Warming Potential (4)** | 1 | 21 | 310 | 23,900 |

Notes:
1. Calculation methods and emission factors from ARB, "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions," amended 12/16/10; effective 1/1/12.
2. 40 CFR 98, Table C-1
3. 40 CFR 98, Table C-2
4. 40 CFR 98, Table A-1.

**Table 5 Greenhouse Gas Emissions, PPEC**

| Unit | Rated Capacity, MW | Operating Hours per year | Maximum Fuel Use, MMBtu/yr | BTU/kWH at ISO conditions | Estimated Gross Annual MWh, 3 CTGs | Maximum Emissions, 3 CTGs metric tons/yr | | | | Estimated Emissions, metric tons/MWh | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | CO2 | CH4 | N2O | SF6 | CO2 | CH4 | N2O |
| **Turbine, baseload** | 103.3 | 4000 | 3,731,196 | 9,030 | 1,239,600 | 593,484 | 11.19 | 1.12 | 0.00 | 0.479 | 9.03E-06 | 9.03E-07 |
| **Turbine, startup** | 51.6 | 83 | 45,475 | 10,576 | 12,900 | 7,233 | 0.14 | 0.01 | 0.00 | 0.561 | 1.05E-05 | 1.06E-06 |
| **Turbine, shutdown** | 51.6 | 83 | 45,475 | 10,576 | 12,900 | 7,233 | 0.14 | 0.01 | 0.00 | 0.561 | 1.05E-05 | 1.06E-06 |
| **Total** | -- | -- | 3,822,146 | | 1,265,400 | 608,951 | 11 | 1 | 0 | 0.480 | 9.06E-06 | 9.06E-07 |
| **CO2eq** | | | | | | 608,951 | 241 | 355 | 0 | | | |
| | | | | | TOTAL | 609,547 | | | | | | |

Notes:
1. Operating hours based on 4000 hours of normal operation +500 startup/shutdown cycles
2. Fuel use based on 100% firing at near-ISO conditions during normal operations; 50% firing (average) during startup and shutdown. Startup = 10 minutes; shutdown = 10 minutes
3. Annual MWh based on 100% during normal operations; 50% (average) during startup and shutdown.

**Table 6 Greenhouse Gas Emissions, (GE Combined Cycle, based on Oakley)**

| Unit | Rated Capacity, MW | Operating Hours per year | Maximum Fuel Use, MMBtu/yr | BTU/kWH at ISO conditions | Estimated Gross Annual MWh, 3 CTGs | Maximum Emissions, 3 CTGs metric tons/yr | | | | Estimated Emissions, metric tons/MWh | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | CO2 | CH4 | N2O | SF6 | CO2 | CH4 | N2O |
| Turbine, CC baseload | 312.0 | 4,000 | 8,426,496 | 6,752 | 1,248,000 | 446,773 | 8.43 | 0.84 | 0.00 | 0.358 | 6.75E-06 | 6.75E-07 |
| Turbine, SC to CC full load | 262.5 | 1,184 | 2,583,851 | 8,310 | 310,923 | 136,996 | 2.58 | 0.26 | 0.00 | | | |
| Turbine, hot start | 104.4 | 104.5 | 139,970 | 12,829 | 10,910 | 7,421 | 0.14 | 0.01 | 0.00 | | | |
| Turbine, cold start | 104.4 | 39 | 52,221 | 12,829 | 4,070 | 2,769 | 0.05 | 0.01 | 0.00 | | | |
| Turbine, shutdown | 104.4 | 250 | 334,750 | 12,829 | 26,093 | 17,748 | 0.33 | 0.03 | 0.00 | | | |
| Aux Boiler | -- | 5000.0 | 246,422 | | | 13,065 | 0.25 | 0.02 | 0.00 | | | |
| Total | -- | -- | 11,783,710 | | 1,599,996 | 624,772 | 12 | 1 | 0 | 0.390 | 7.36E-06 | 7.36E-07 |
| CO2eq | | | | | | 624,772 | 247 | 365 | 0 | | | |
| | | | | | TOTAL | 625,385 | | | | | | |

Notes:
1. Operating hours based on 4000 hours of normal operation +500 startup/shutdown cycles
2. Fuel use based on 100% firing at ISO conditions during normal operations; 50% firing (average) during startup and shutdown. Cold start = 45 minutes; warm start = 14 minutes; shutdown = 30 minutes.
3. Annual MWh based on 100% during normal operations; 50% (average) during startup and shutdown.
4. Warm/hot start: 120 minutes to ST full load
5. Cold start: 210 minutes to ST full load

**Table 7 Greenhouse Gas Emissions, ((Siemens combined cycle, based on Carlsbad)**

| Unit | Rated Capacity, MW | Operating Hours per year | Maximum Fuel Use, MMBtu/yr | BTU/kWH at ISO conditions | Estimated Gross Annual MWh, 3 CTGs | Maximum Emissions, 3 CTGs metric tons/yr | | | | Estimated Emissions, metric tons/MWh | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | CO2 | CH4 | N2O | SF6 | CO2 | CH4 | N2O |
| **Turbine, CC baseload** | 279.0 | 4,000 | 8,000,000 | 7,168 | 1,116,000 | 424,160 | 8.00 | 0.80 | 0.00 | 0.380 | 7.17E-06 | 7.17E-07 |
| **Turbine, SC to CC full load** | 243.5 | 684 | 1,397,572 | 8,392 | 166,538 | 74,099 | 1.40 | 0.14 | 0.00 | | | |
| **Turbine, hot start** | 104.0 | 89.6 | 109,939 | 11,798 | 9,318 | 5,829 | 0.11 | 0.01 | 0.00 | | | |
| **Turbine, cold start** | 104.0 | 10 | 12,761 | 11,798 | 1,082 | 677 | 0.01 | 0.00 | 0.00 | | | |
| **Turbine, shutdown** | 104.0 | 250 | 306,750 | 11,798 | 26,000 | 16,264 | 0.31 | 0.03 | 0.00 | | | |
| **Total** | -- | -- | 9,827,022 | | 1,318,938 | 521,029 | 10 | 1 | 0 | 0.395 | 7.45E-06 | 7.45E-07 |
| **CO2eq** | | | | | | 521,029 | 206 | 305 | 0 | | | |
| | | | | | **TOTAL** | 521,540 | | | | | | |

Notes:

1. Operating hours based on 4000 hours of normal operation +500 startup/shutdown cycles
2. Fuel use based on 100% firing at ISO conditions during normal operations; 50% firing (average) during startup and shutdown.
3. Annual MWh based on 100% during normal operations; 50% (average) during startup and shutdown.
4. Warm/hot start: 12 minutes to GT full load + 45 minutes to ST full load
5. Cold start: 12 min to GT full load + 113 min to ST full load

## Maintenance Tasks

*Comment: The letter you emailed on 3/19/2012 regarding GHG BACT does not describe the maintenance tasks and associated frequency that PPEC intends to conduct for the LMS100 turbines. My staff had asked you to provide us with a detailed description of the tasks that PPEC expects to conduct, to allow us to craft maintenance conditions that, combined with a one time heat rate demonstration, might constitute GHG BACT for the project. If you still want us to consider this approach that you proposed, please provide specific details of the tasks and associated frequencies that would be included in the turbine maintenance plans that you referenced in the draft permit condition included in your letter.*

**Response:** As we discussed in our meeting at Region 9 headquarters on March 7, 2012, the language contained in the proposed maintenance condition was based upon the maintenance requirements in the RICE NESHAPS.

Applicant has contacted the manufacturer and received information regarding specific maintenance activities that are intended to keep the turbines operating at maximum efficiency. In addition, we reviewed PSD GHG BACT determinations made by EPA for other recent projects. Based on these sources of information, we have developed the following proposed permit condition language; the specific details of maintenance tasks and associated frequencies that you requested are included below.

The heat rate limits that Applicant proposed in its March 19, 2012 letter were based on estimated turbine performance data provided by GE.[3] These values represent the expected performance of a new turbine, based on the design and manufacturing tolerances to build LMS100 machines. Due to the tolerances of manufacturing, assembly, and construction, the actual performance of a specific new turbine could be 3% higher or lower than the expected value. While suitable for use as a basis for estimating emissions, these data are not guaranteed by GE, and require adjustment for the variability in construction and installation, as well as instrument uncertainty, before being used as a compliance requirement. After further consultation with GE and with the contractor who will be building the facility, Applicant is proposing a heat rate limit consistent with the guarantee provided by GE. Applicant proposes a compliance requirement equal to the highest heat rate in the cases used to evaluate emissions, plus 3% to account for the factors described above. In order to avoid additional uncertainty (and therefore the need for additional compliance margin), the proposed heat limit is based on gross power production.

1. GHG BACT requirements
    a. Operating Requirements
        i. Permittee shall minimize emissions at all times, including during start-up and shutdown activities, by operating and maintaining the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.

[3] Please note that the values in the March 19, 2012 letter were incorrectly identified as based on net power production. They were actually based on gross power production.

b. Performance Test
   i. Within 90 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, Permittee shall conduct a performance test to demonstrate that the thermal heat rate ($btu_{hhv}/kw\text{-}hr_{gross}$) of each turbine at full load does not exceed 9,196 btu/kw-hr.
      1. $Btu_{hhv}$ is the heat content of the fuel flow into the turbine
      2. $Kw\text{-}hr_{gross}$ is the power production measured at the generator terminals
      3. The heat rate performance test shall be conducted according to the requirements of the American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance, ASME PTC 22.

c. Monitoring
   i. Permittee shall measure and record, for each turbine, the following:
      1. Gross energy output ($MWh_{gross}$) on an hourly basis
      2. Fuel consumption (MMSCF of natural gas) on an hourly basis

d. Maintenance requirements
   i. On or after initial performance testing, permittee shall use the combustion turbine and plant-wide energy efficiency processes, work practices and designs as represented in the permit application.

   ii. Permittee shall prepare a Maintenance Plan for each turbine. The Maintenance Plan shall follow manufacturer's written instructions or operator-developed procedures that provide, to the extent practicable, for the maintenance and operation of the turbine in a manner consistent with good air pollution control practice for minimizing emissions. The Maintenance Plan shall include, but not be limited to, the following requirements:
      1. Permittee shall maintain each turbine, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.
      2. Annual maintenance shall be performed no less frequently than once every four calendar quarters. Maintenance shall include:
         a. Generator testing
         b. Boroscope inspection of turbine passes
         c. Control system check
      3. Major overhaul shall be conducted as recommended by the manufacturer, at 25,000 operating hours (or other period recommended in writing by the manufacturer).

   iii. Permittee shall maintain each turbine according to the Maintenance Plan.

e. Recordkeeping requirements

i. Permittee shall maintain a log describing maintenance and repair activities, including the following information:
   1. Date of activity
   2. Description of activity
   3. For scheduled maintenance, the elapsed time, hours of turbine operation, or other applicable measure since the activity was last performed.
   4. For scheduled maintenance, the elapsed time, hours of turbine operation, or other applicable measure until the activity should next be performed.

With this submission, we believe EPA has all of the information it needs to establish BACT requirements for all pollutants, including GHGs, for the Pio Pico Energy Center project. To that end, Applicant looks forward to receipt of the draft PSD permit for the Pio Pico Energy Center.

Sincerely,

Steve Hill

Attachments

cc: John McKinsey, Stoel Rives LLP
David Jenkins, Apex Power Group
Steve Moore, SDAPCD

James P. Avery
Senior Vice President - Power Supply

8330 Century Park Court
San Diego, CA 92123-1530
Tel: 858-650-6102
Fax: 858-650-6106
javery@semprautilities.com

April 4, 2012

SENT BY EMAIL AND FEDERAL EXPRESS

Gary Chandler
APEX Power Group, LLC
2542 Singletree Lane
South Jordan, UT 84095

**Re: Pio Pico Energy Center**
**Application for Prevention of Significant Deterioration Permit**

Dear Mr. Chandler:

San Diego Gas & Electric Company (SDG&E) understands that Pio Pico Energy Center LLC (Pio Pico) has applied to the U.S. Environmental Protection Agency for a Prevention of Signification Deterioration permit for the Pio Pico Energy Center (the Project). Pio Pico proposed the Project in response to SDG&E's Request for Offer (RFO) dated June 9, 2009, and this letter summarizes key points relating to the RFO.

The California Public Utilities Commission (CPUC) issued Decision 07-12-052 on December 20, 2007. This decision approved SDG&E's long-term resource plan.[1] In the decision, the CPUC required "SDG&E to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources." Decision 07-12-052 at 115, 278.

SDG&E issued the RFO in response to the CPUC's decision. The RFO was for "peaking or intermediate-class resources." RFO at 2.[2] As the RFO explained, "SDG&E requires flexible

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1 Decision 07-12-052 is voluminous and is therefore not appended to this letter. The decision is available on the CPUC website at <http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/76979.pdf>. The CPUC modified Decision 07-12-052 in Decision 08-11-008, dated November 6, 2008, which is available on the CPUC website at <http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/76979.pdf>.

2 The RFO is appended as Attachment 1.

resources that are capable of providing regulation during the morning and evening ramps and/or units that can be started and shut down as needed." RFO at 2.

SDG&E evaluated all bids, including Pio Pico's bid for the Project, on "an expected cost analysis covering both quantitative and qualitative information . . . on the basis of a least cost/best fit (LCBF) analysis." RFO at 8. SDG&E selected the Project based on this least cost/best fit analysis.

SDG&E and Pio Pico then executed a Power Purchase Tolling Agreement (Agreement) on February 2, 2011. SDG&E has applied to the CPUC for authority to enter into the Agreement, and the proceeding on the application is pending.[3]

I hope that this information is helpful.

Sincerely,

James P. Avery
Senior Vice President – Power Supply
San Diego Gas & Electric Company

3 The documents filed in the proceeding are available on the CPUC website at http://docs.cpuc.ca.gov/published/proceedings/A1105023.htm.

# ATTACHMENT 1

# REQUEST FOR OFFERS
# for
# DEMAND RESPONSE
# and
# SUPPLY RESOURCES

**June 9, 2009**

**San Diego Gas & Electric Company**
Electric and Gas Procurement Department
8315 Century Park Court,
San Diego, CA 92123-1593

## 1. Scope of Supply[1]

San Diego Gas & Electric Company (SDG&E) is issuing this Request for Offers (RFO) for demand response and supply resources to support reliability within the SDG&E service territory, supply energy to bundled customers and/or meet other portfolio needs including Resource Adequacy (RA) requirements. All resources that can meet the obligations set forth below are welcome to bid their offers into this RFO (Offer(s)); however, all renewable resources are strongly encouraged to participate in a separate renewables-only solicitation, which SDG&E issues annually[2]. SDG&E anticipates this RFO will produce contracts from respondents (Respondent(s)) as indicated below:

<table>
<tr><th></th><th colspan="2">Local Resources</th><th colspan="2">Resources Outside SDG&E</th></tr>
<tr><th></th><th>Short-Term</th><th>Long-Term</th><th>Short Term</th><th>Long Term</th></tr>
<tr><td><u>Product 1</u>:<br>Demand Response</td><td>Term:<br>3 years<br>Delivery Starts:<br>2012</td><td></td><td></td><td></td></tr>
<tr><td><u>Product 2</u>:<br>New Generation</td><td></td><td>Term:<br>20 years<br>Delivery Starts:<br>2010 - 2014</td><td></td><td></td></tr>
<tr><td><u>Product 3</u>:<br>Existing Resources</td><td>Term:<br>1 year / 2 years<br>Delivery Starts:<br>2010 or 2011</td><td></td><td></td><td></td></tr>
<tr><td><u>Product 4</u>:<br>Existing Resources</td><td></td><td></td><td>Term:<br>2 years<br>Delivery Starts:<br>2010</td><td></td></tr>
<tr><td><u>Product 5</u>:<br>Existing Resources</td><td></td><td>Term:<br>10 years<br>Delivery Starts:<br>2012</td><td></td><td></td></tr>
<tr><td><u>Product 6</u>:<br>New or Existing Resources</td><td></td><td></td><td></td><td>Term:<br>10 years<br>Delivery Starts:<br>2012</td></tr>
<tr><td><u>Product 7a</u>:<br>Firm LD Energy</td><td rowspan="2">Term:<br>2 years / 4 years<br>Delivery Starts:<br>2010 or 2012</td><td></td><td rowspan="2">Term:<br>2 years / 4 years<br>Delivery Starts:<br>2010 or 2012</td><td></td></tr>
<tr><td><u>Product 7b</u>:<br>Resource Adequacy</td><td></td><td></td></tr>
</table>

[1] Amounts requested in each product category may vary based upon CAISO determinations on RMR, local zone definition, unit retirement, and the quantity selected in other product categories.

[2] To be notified of pending Renewable-only solicitations, please email contact information to RenewableRFO@semprautilities.com.

General characteristics of each product are described below. SDG&E anticipates that all Offers received will provide SDG&E with a menu of resources from which it can select to fulfill its short- and long-term needs. The capacities listed are not a guarantee of purchase amounts for each product, but rather estimates of potential volumes. The final purchase amounts will depend on factors including evolving resource planning considerations, the number of Offers received for each product type and potential overlap in product characteristics from various Offers. Offered prices for Products 1 through 6 and 7b are valid and binding upon the Respondent until contract execution; there will be no opportunities to refresh Offer prices. There will be one opportunity to refresh Offer prices for Product 7a as indicated in the schedule on Section 3 RFO Schedule. Tolling products 2-6 will include supply of all capacity attributes including Resource Adequacy and Ancillary Services if available.

**Product 1 - Demand Response**

SDG&E seeks Demand Response products for a three year term. Initial load reduction will commence on May 1st 2012. This product must be a means of reducing an end-use customer's demand and/or energy usage during a demand response event, must be for at least 1.0 MW in the aggregate and be within SDG&E's service territory. The demand and/or energy reduction must be measureable. The Offer must provide, in sufficient detail, the Demand Response product, the process for delivering Demand Response and the manner in which it will meet the minimum guidelines specified in Section 6 Offer Requirements of this solicitation.

**Product 2 - New Local[3] Generation Projects, online in 2010 - 2014.**

SDG&E seeks a minimum of 100 MW of peaking or intermediate-class resources as new construction or expansion projects within SDG&E's territory. Any resulting contract will be a tolling agreement with a term of 20 years and online dates of May 1- or October 1 in either 2010, 2011, 2012, 2013 or 2014. The generation must be located physically within SDG&E's service territory (as more specifically described in the Addendum) or have its sole generator transmission system interconnection (gen-tie) directly interconnected to the electric network internal to SDG&E's local area as currently defined by the California Independent System Operator ("CAISO") such that the unit supports SDG&E's Local RA requirement. Units located within CAISO's proposed expanded local area for SDG&E (see Addendum) should submit Offers in other products of this solicitation. Products offered in this category shall be capable of operating under all permits at annual capacity factors of a minimum of 30%with an availability of ~98%. It is anticipated that heat rates will be no higher than 10,500 btu/kWh. For this product, SDG&E requires flexible resources that are capable of providing regulation during the morning and evening ramps and/or units that can be started and shut down as needed. In addition, SDG&E will include the additional value provided from projects that can provide quick start operations[4] in the ranking of Offers. SDG&E also requires that each Offer contain pricing for, and an option to provide, black start capability.

**Product 3 - Existing Local Resources, delivering in 2010 and/or 2011**

SDG&E seeks a minimum of 400 MW of existing resources currently operating within SDG&E's territory for deliveries in 2010 and 2011. Any resulting contract will be a tolling agreement with a term of up to 2 years with a start date of January 1, 2010, or a 1 year term with a start date of January 1, 2010 or January 1, 2011. Offers for this product must be existing generation capacity that is currently recognized by the CAISO as counting towards SDG&E's service area Local Capacity Requirement. Respondents must provide Offers for deliveries in both 2010 and 2011 and pricing may differ between the years. However, SDG&E may at its discretion contract with the Respondent for

[3] "Local" for purposes of satisfying Resource Adequacy, is defined by the CAISO and generally described in the Addendum below.

[4] Respondents will specify resource ramp-up rates and other operating characteristics within the offer forms.

either or both years. For this product, SDG&E requires flexible resources that are capable of providing regulation during the morning and evening ramps and/or units that can be started and shut down as needed. In addition, SDG&E will include the additional value provided from projects that can provide quick start operations[5] in the ranking of Offers. SDG&E also requires that each Offer contain pricing for, and an option to provide, black start capability.

**Product 4 - Existing Regional Resources, delivering in 2010 and 2011**
SDG&E seeks a minimum of 200 MW of existing resources currently operating outside of SDG&E's territory. Any resulting contract will be a tolling agreement with a term of 2 years starting on January 1, 2010. This product must deliver into CAISO's SP-15. For this product, SDG&E requires flexible resources that are capable of providing regulation during the morning and evening ramps and/or units that can started and shut down as needed. In addition, SDG&E will include the additional value provided from projects that can provide quick start operations[5] in the ranking of Offers.

**Product 5 - Existing Local Resources, delivering in 2012-2021**
SDG&E seeks a minimum of 400 MW of existing resources currently operating within SDG&E's territory. Any resulting contract will be a tolling agreement with a term of 10 years and a start date of January 1, 2012 to qualify. Offers for this product must be existing generation located physically within SDG&E's service territory (as more specifically described in the Addendum) or have its sole generator transmission system interconnection (gen-tie) directly interconnected to the electric network internal to SDG&E's local area as currently defined by the California Independent System Operator ("CAISO") such that the unit supports SDG&E's Local RA requirement. Units located within CAISO's proposed expanded local area for SDG&E (see Addendum) should submit Offers in other products of this solicitation. In consideration of California State Once Through Cooling (OTC) goals and pending Water Board rules, any Offer for supply from a unit utilizing OTC will be offered a contract with SDG&E that consists of a 2 year transaction with the possibility to extend for eight – 1 year options. OTC offers shall not include proposals for upgrades or retrofits of OTC facilities. The decision to exercise the option will be based upon future rules[6] governing OTC or SDG&E's sole discretion given its portfolio need. For this product, SDG&E requires flexible resources that are capable of providing regulation during the morning and evening ramps and/or units that can be started and shut down as needed. In addition, SDG&E will include the additional value provided from projects that can provide quick start operations[5] in the ranking of Offers. SDG&E also requires that each Offer contain pricing for, and an option to provide, black start capability.

**Product 6 - All-Source Regional Resources, 2012-2021**
SDG&E seeks minimum of 200 MW of new construction, expansion, or existing resources currently operating outside of SDG&E's territory. Any resulting contract will be a tolling agreement with a term of 10 years and deliveries will begin on May 1, 2012. This product must deliver into CAISO's SP-15. For this product, SDG&E requires flexible resources that are capable of providing regulation during the morning and evening ramps and shutting down at night. In addition, SDG&E will include the

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[5] Respondents will specify resource ramp-up rates and other operating characteristics within the offer forms.

[6] From the California State Water Resources Control Board website: *The State Water Board staff is working on a draft statewide policy to implement section 316 (b) of the Clean Water Act that controls the harmful effects of once-through cooling water intake structures on marine and estuarine life. Since 1972, the Clean Water Act has required, in Section 316 (b), that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. The projected release date for a draft Substitute Environmental Document is the end of the summer.* For additional information, please visit: http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml

additional value provided from projects that can provide quick start operations[6] in the ranking of Offers. In consideration of California State Once Through Cooling (OTC) goals and pending Water Board rules, any Offer for supply from a unit located in California utilizing OTC will be offered a contract with SDG&E that consists of a 2 year transaction with the possibility to extend for eight – 1 year options. OTC offers shall not include proposals for upgrades or retrofits of OTC facilities. The decision to exercise the option will be based upon future rules[6] governing OTC or SDG&E's sole discretion given its portfolio need. If the CAISO expands SDG&E's Local RA area as described in the addendum, SDG&E could, at its sole discretion, evaluate Product 6 Offers that are located within the expanded area as if it were a Product 5 Offer.

**Product 7 Firm Liquidated Damages (LD) Energy and/or Resource Adequacy**
SDG&E seeks a minimum of 200 MW of Firm LD Energy and/or Resource Adequacy Purchases. Resources may be within or outside of SDG&E service area.

Product 7a: Third Quarter, 6x16, on-peak Firm LD energy products conforming to Schedule C of the Western States Power Pool. Any resulting agreement will be an EEI agreement for short-term, block power purchases. Respondents may provide Offers for the following delivery periods: 1) for deliveries in 2010 and 2011 and/or 2) deliveries in 2012 and 2013. If a Respondent provides Offers for both options, SDG&E may at its discretion contract with the Respondent for either or both options. Resources outside of SDG&E must deliver to SP-15. For Product 7a, SDG&E will shortlist projects within the timeframes indicated in the schedule in Section 3 of this RFO. Refreshed pricing of shortlisted Offers will be allowed only once and by the date indicated in the schedule. Respondents are caution that if refreshed prices exceed the competitive range, the Offer may be rejected.

Product 7b: Respondents shall Offer System Resource Adequacy (and local if within the SDG&E Local Area). Any resulting agreement will be a WSPP agreement for Resource Adequacy. Respondents may provide Offers for the following delivery periods: 1) for deliveries in 2010 and 2011 [Q3 or full year] and/or 2) deliveries in 2012 and 2013 [Q3 or full year]. If a Respondent provides Offers for both options, SDG&E may at its discretion contract with the Respondent for either or both options.

Respondents may provide Offers for a single product and term or a combination of Offers, providing SDG&E with flexibility to match Offers and fill its required energy and capacity needs. For products seeking new or expanded generation resources, the Respondent shall be responsible for development, permitting, financing, and construction of any required facilities. The generating facility and transmission interconnection must be designed and constructed in conformance with CAISO's Tariff, applicable CPUC and/or FERC rules, orders, and/or regulations, and SDG&E's specifications.

## 2. RFO Website and Communication

The website for this solicitation is http://www.sdge.com/2009SupplyResourcesRFO/ . All forms and documents necessary to submit Offers are available for download at the RFO Website. Respondents will also submit Offers electronically via this website. (See RFO Section 4.0 RFO Response for additional information.) Please check the website periodically as SDG&E will post all solicitation announcements, including scheduling changes or RFO amendments at this website.

All questions or other communications regarding this RFO should be submitted via e-mail to the RFO's mailbox: rfo@semprautilities.com. All questions and answers will be posted anonymously at the RFO Website. SDG&E will not accept questions or comments in any other form, except during the bidders' conference.

## 3. RFO Schedule

SDG&E will host a pre-bid conference on the date and time indicated below. Participation in the pre-bid conference is NOT mandatory in order to submit an Offer. Any party interested in attending this pre-bid conference should download the Pre-Bid Conference Registration Form from the RFO Website and email the form to rfo@semprautilities.com. Details on the exact location of the pre-bid conference will be posted on the RFO Website as soon as it is available.

SDG&E reserves the right to revise this schedule at SDG&E's sole discretion and will post such changes on the RFO Website. Respondents are responsible for accessing the RFO website for updated schedules and possible amendments to the RFO or the solicitation process. Short-listed Respondents will be notified of interview date, time, and meeting room location. All interviews will be conducted at SDG&E's Century Park complex.

| # | MILESTONE | DATE |
|---|---|---|
| 1 | **RFO Issued** | **June 9, 2009** |
| 2 | DEADLINE TO REGISTER for PRE-BID CONFERENCE<br>Those intending to bid must register to receive a username/password in order to upload electronic Offers. | June 25, 2009 |
| 3 | Pre-Bid Conference at 10:00am in San Diego, CA | July 8, 2009 |
| 4 | DEADLINE TO SUBMIT QUESTIONS<br>Question submittal cut-off date. | July 27, 2009 |
| 5 | DEADLINE TO REGISTER<br>Those intending to bid must register to receive a username/password in order to upload electronic Offers. | August 5, 2009 |
| 6 | **CLOSING DATE: Offers uploaded and received by noon**<br>(San Diego local prevailing time) | **August 10, 2009** |
| 7 | Hard-copies of Offers must be received at SDG&E's offices | August 12, 2009 |
| 8 | Product 3 and Product 7a:<br>Shortlisting, negotiation and contract execution | Within 3 months after closing date |
| 9 | Products 1, 2, 4, 5, 6, 7b:<br>Shortlisted Bidders notified / Negotiation commences | 3 months after closing date |
| 10 | ~~Products 1, 2, 4, 5, 6, 7b:~~<br>Deadline to refresh Product 7a offered pricing. | No later than 2 months after shortlist notification |
| 11 | Products 1, 2, 4, 5, 6, 7b:<br>Contracts Executed | Approx. 3 – 9 months after shortlisting |
| 12 | Products 1, 2, 4, 5, 6, 7b:<br>Contracts filed with CPUC | Approx. 1 - 2 months after contract execution |
| 13 | Products 1, 2, 4, 5, 6, 7b:<br>CPUC approves contracts | Typically 6 - 9 months after contract filing<br>(but could be longer) |

## 4. RFO Response

Any party interested in submitting an Offer must fill-out and email to rfo@semprautilities.com the RFO Registration Form (available from the RFO Website). SDG&E will process the form and provide the interested party instructions necessary to upload Offers, a username/password combination and access to the offer upload link (see below).

SDG&E **requires** that all Offers submitted pursuant to this RFO contain at a minimum, the items listed below. All forms and documents referenced below are available on the RFO Website.

a) the information requested in the Submittal Forms using the forms provided. The forms should be submitted in editable electronic form for efficient processing by SDG&E.
b) Respondents must redline comments on the pro forma agreement applicable to the Offer. In order to evaluate Offers against each other in each Product class, SDG&E urges that Respondents develop their Offers using existing Terms and Conditions of the pro forma agreements. Substantial, material mark-ups may result in an Offer being deemed non-conforming.
c) Credit. Respondent's Offer **must include** a completed credit application (available on the RFO website).
d) Respondents to products seeking new or expanded generating resources, must submit a detailed Gantt chart (or equivalent alternative) which outlines all major project milestones (including but not limited to permitting, engineering, site preparation, equipment contract and delivery and construction). The project timeline will also include milestones associated with major cost commitments (>$500,000). The workplan should also include a description of any uncertainties, where any changes would still result in not meeting the required on line date.

All Offers must be uploaded to SDG&E via the RFO Website by the date and time indicated in the schedule above. One original hardcopy Offer, identical to the electronic submittal and signed by an authorized officer of the Respondent, shall also be sent to the address shown below and must be received by SDG&E by the date indicated in the schedule. Contents of the electronic Offer submittal and the original hardcopy signed Offer shall be identical. Any conflicts between the information set forth in an electronic Offer and the signed Offer shall be resolved in favor of the signed Offer. All Offer materials and information submitted shall be subject to the confidentiality provisions of this RFO.

**San Diego Gas & Electric Company**
**Electric and Gas Procurement Department**
**Attn: Supply Resource RFO**
**8315 Century Park Court, CP 21D**
**San Diego, CA 92123-1548**

## 5. Project Timeline

Respondents must demonstrate that they have or are in process of getting all necessary permits (including air and building permits), site control, engineering designs and transmission interconnection studies. Sufficient documentation must be provided to evidence that the project can come online by the proposed date.

## 6. Offer Requirements

1. The Respondent shall be responsible for all costs for land, development, permitting (including emissions offsets, if applicable), engineering, procurement, and construction and for associated taxes, insurance, financing and bonding. The Respondent shall be operationally responsible for all development work and construction, including acquisition of land, permitting (including emissions offsets), engineering, procurement, and construction up to the highest industry standards and in accordance with time critical milestones and schedules.

2. The Respondent shall be responsible for all electric system and gas pipeline upgrades and / or extensions if required under and in accordance with applicable gas and electric tariffs. See http://www.sdge.com/tariff .

3. The Respondent must have all necessary water rights consistent with the generating resource needs. Resources located on leased properties may be accepted upon review of the lease terms, but must have a minimum lease term that covers the term of the PPA offered.

4. Respondent must identify all necessary emissions offsets and the associated costs which will be incorporated into their Offer. All Offers must comply with all existing air quality laws and be compliant with the CPUC Emissions Performance Standards (as adopted in R.06-04-009) on GHG.

5. For all products where the resulting contract will be tolling agreements, Respondents must provide generating facilities designed and permitted for operation for a minimum availability of 2,700 hours per year annual operations for peaking and intermediate duty.

6. SDG&E will, if requested, be responsible for the purchase and transportation cost of natural gas or other fuels to the plant site during commissioning, testing and contract term, for tolling agreements. In such instance, electric output during commissioning and testing shall be delivered at no charge to SDG&E, and SDG&E shall be entitled to receive all revenues for such energy.

7. For new development, permitting information provided by the Respondent shall include status of existing and required additional new permits, including any additional required approvals, along with a permitting and approval schedule. Such schedule must demonstrate an achievable online date of no later than that deadline dates stated in the Product descriptions.

8. For Product 1 Demand Response, the minimum criteria are indicated below.

    a. Offers must meet Resource Adequacy requirements for Demand Response as set forth by the CPUC in D.05-10-042.
    b. Offers should be for three (3) year Demand Response product Offer to provide load reduction beginning May 1, in 2012.
    c. Ability to fully respond to an event notification within 10 minutes.
    d. Load must be curtailable between 12:00 PM and 6:00 PM.

e. Offers must conform with all CAISO requirements for Demand Response Resources[7], including but not limited to Metering and Telemetry requirements, as may be updated from time to time.
f. Offers must comply with the policy guidance of the Energy Action Plan I and II and be in alignment with California's Demand Response Vision for the Future.[8]
g. Offers must be for load not yet committed to other programs.
h. Offered loads must be curtailable under a Direct Load Control (DLC) program.
i. Offered loads must have an average monthly maximum greater than 100kW for at least three (3) of the most current twelve (12) months.
j. Offers must be targeted toward nonresidential customers with a minimum demand of 100kW. Offers targeted at residential and/or small business customers with demands <100kW will not be considered.

Generation resources located on the customer side of the meter, such as back –up generation, will not qualify as a Demand Response product in this Offer.[9]

Alternative Offers may be submitted. At SDG&E discretion, alternative Offers may be evaluated and considered. If alternative Offers are submitted, please clearly state (identify) the alternative Offers.

Please note that any resultant contract will include provisions for:

a. A Non-Performance penalty for capacity load reduction shall be applied. For example, a non-performance calculation may be similar as SDG&E's Capacity Bidding Program CBP. Refer to SDG&E' Schedule CBP - Capacity Bidding Program, Special Condition 6 in http://www.sdge.com/regulatory/elec_misc.shtml
b. A Non-Performance penalty for load reduction during an event shall be applied. Energy load reduction shortfall during an event shall be considered non-performance and an adjustment will be required in order to compensate for any failure of the contractor to deliver committed load reductions. For example, a non-performance calculation may be similar as SDG&E's Capacity Bidding Program CBP Schedule.

At the request of SDG&E, the selected Respondent will be required to provide the following documents during contract negotiations:

a. Audited financial statements, including balance sheet, statement of cash flows, and income, for 2007 and 2008; OR
b. Complete income tax returns for 2007 and 2008.

## 7. Binding Offer Evaluation

SDG&E anticipates evaluating Offers for different Products on different timelines. In general, supply offers for 2010-2011 delivery dates will be evaluated first. Supply Offers for 2012 – on delivery dates will be evaluated second. Offers that are determined to meet the threshold requirements will be evaluated on the basis of an expected cost analysis covering both quantitative and qualitative information. In general, Offers that meet RFO requirements will be evaluated on the basis of a least cost/best fit (LCBF) analysis. The quantitative analysis will look at the total expected cost to SDG&E's bundled customers when the Offer is added to SDG&E's resource portfolio. The quantitative components of this analysis include the items listed below.

[7] http://www.caiso.com/1893/1893e350393b0.html
[8] California Demand Response: A Vision for the Future, D. 03-06-032, Appendix A.
[9] D.06-11-049 (mimeo at pp.57-58) discusses the Commission's policy regarding back-up generation options.

SDG&E reserve the right to evaluate non-conforming Offers and may request additional data from Respondents to bring non-conforming Offers into conformance.

1. Binding Offer prices for both capacity and energy (Offers deemed by SDG&E to contain unreasonably low or high prices will be rejected).

2. Transmission system upgrade costs necessary for the new generation resource to satisfy grid reliability and deliverability requirements for new capacity.

3. Congestion costs - Potential for SDG&E incurred congestion costs will be assessed, as well as SDG&E's ability to hedge these costs.

4. Impacts on existing SDG&E financial structure, such as debt equivalence and/or the effect of FIN 46, may be considered in the evaluation process.

5. Changes to SDG&E bundled customer's total GHG Emissions will also be valued. SDG&E will determine the forecasted change in total GHG emissions from adding the Offer to SDG&E's portfolio. Portfolio GHG increases or reductions will be valued based on previous CPUC direction.

In accordance with CPUC D.07-12-052 preference will be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, at minimum, qualitative preference to Offers involving repowering of these units or Offers for new facilities at locations in or near the load pockets in which these units are located." (p.113) and further "IOUs are to consider repowered or replacement options presented in a RFO..... before they choose options developed on Greenfield sites, or make a showing that justifies their decision not to do so (p.229).

Qualitative factors used to differentiate Offers include the following:

1. Brownfield vs. greenfield – the proposed location will be assessed to determine if the project is located at a brownfield or greenfield site.

2. Environmental stewardship – SDG&E will assess the project team's history and any special benefits of the specific Offer.

3. Financing plan – the Offer will be assessed as to the plan and likelihood of the project securing the necessary financing.

4. Technology, major equipment manufacturers and operational flexibility. The evaluation will include an assessment of the proposed technology's commercial operating history, and the manufacturer's U.S. presence and experience.

5. The proposed facility will be evaluated from the perspective of maximizing the operational flexibility of generating assets available to SDG&E. This incorporates unit capabilities that include size, start-up time, load response, minimum up and down times.

6. Development risk – consideration will be given to regulatory and other risks as appropriate that could diminish the viability of the project.

7. Corporate capabilities and proven experience

8. Ability to meet schedule

9. Project team (environmental, engineering, equipment procurement, construction) – Project team will be assessed on whether the project team has demonstrated experience with the specific technology and implementation plan they are proposing.

10. Credit Risk

Portfolios of Offers that are short listed based on qualitative and quantitative criteria will be analyzed using production cost modeling. Offers for local capacity will be analyzed and ranked first until the combined capacity of the short listed Offers meets local need requirements. The remaining Offers will then be evaluated and ranked to meet the remaining system need.

SDG&E requests that Respondents who believe their Offers have any important qualitative benefits elaborate on them in their Offer.

SDG&E will utilize the information provided on the Offer Response Forms to evaluate all Offers. Respondents are responsible for the accuracy of all figures and calculations. Errors discovered during negotiations may impact Respondents' standing on the short-list.

## 8. Binding Offer Duration

All Offers into this RFO (with the exception of Product 7 as noted elsewhere in this document) are binding as of the submittal date and must remain binding, open and valid through SDG&E's Offer evaluation, price negotiations, contract execution between SDG&E and the selected Respondent(s), and any required CPUC and FERC approval. No Offer adjustments which increase costs shall be permitted after submission of Binding Offer.

## 9. Confidentiality

Except with the prior written consent of SDG&E, Respondents may not disclose (other than by attendance alone at any meeting to which more than one Respondent is invited by SDG&E) to any other Respondent or potential Respondent their participation in this RFO, and Respondents may not disclose, collaborate on, or discuss with any other Respondent, bidding strategies or the substance of Offers, including without limitation the price or any other terms or conditions of any indicative or final Offer.

SDG&E will use the higher of the same standard of care it uses with respect to its own proprietary or confidential information or a reasonable standard of care to prevent disclosure or unauthorized use of Respondent's confidential and proprietary information that is labeled as "proprietary and confidential" on the Offer page on which the proprietary information appears (confidential information). Respondent shall also summarize the elements of the Offer(s) it deems confidential. The summary must clearly identify whether or not price, project name, location, size, term of delivery, technology type (either collectively or individually) or any other term are to be considered confidential information Confidential information may be made available on a "need to know" basis to SDG&E's directors, officers, employees, an independent third-party evaluator required by the CPUC, agents and advisors (representatives) for the purpose of evaluating Respondent's Offer, but such representatives shall be required to observe the same care with respect to disclosure as SDG&E.

Notwithstanding the foregoing, SDG&E may disclose any of the confidential information to comply with any law, rule, or regulation or any order, decree, subpoena or ruling or other similar process of any court, securities exchange, control area operator, governmental agency or governmental or regulatory authority at any time even in the absence of a protective order, confidentiality agreement or non-disclosure agreement, as the case may be, without notification to the Respondent and without liability or any responsibility of SDG&E to the Respondent.

It is expressly contemplated that materials submitted by a Respondent in connection with this RFO will be provided to the CPUC, its staff, and possibly to the CEC, its staff, SDG&E's Independent Evaluator (IE) and Procurement Review Group (PRG). SDG&E will seek confidential treatment in accordance with CPUC Decision 06-06-066 and any subsequent decision by the CPUC related to confidentiality, with respect to any Respondent confidential information submitted by SDG&E to the CPUC for the purposes of obtaining regulatory approval. SDG&E will also seek confidentiality protection from the CEC for Respondent's confidential information and will seek confidentiality and/or non-disclosure agreements with the PRG. SDG&E cannot, however, ensure that the CPUC or CEC will afford confidential treatment to a Respondent's confidential information or that confidentiality agreements or orders will be obtained from and/or honored by the PRG, CEC, or CPUC.

SDG&E, its representatives, Sempra Energy, and any of their subsidiaries disclaim any and all liability to a Respondent for damages of any kind resulting from disclosure of any of Respondent's information.

## 10. Other Requirements

**CALIFORNIA CLIMATE ACTION REGISTRY**

In D.06-02-032, the CPUC directed SDG&E to include a provision in any power purchase agreement for non-renewable energy that requires the supplier to register and report its GHG emissions with the California Climate Action Registry (CCAR). More information about the CCAR is available at California Climate Action Registry.

Pursuant to D.06-02-032, SDG&E will be required to include a provision in any tolling agreement that will require the supplier to register and report its GHG emissions with the CCAR. Specific registration requirements and reporting protocols with the CCAR will be established, and a method for assigning emissions values to supplies that are unregistered with the CCAR will also be developed.

For more information, see: http://www.cpuc.ca.gov/proceedings/R0604009.htm

**FIN 46 Requirements**

Securities and Exchange Commission rules for reporting power purchase agreements may require SDG&E to collect and possibly consolidate financial information for the facility whose output is being purchased under long-term contractual arrangements. General guidelines include:

a) determination of allocation of risk and benefits
b) proportion of total project output being purchased by SDG&E
c) proportion of expected project life being committed to SDG&E
d) pricing provisions of contract; that is, whether the contract contains fixed long-term prices or pricing that varies over the term of the agreement based on market conditions or other factors

For any Agreements that meet the applicability criteria, SDG&E is obligated to obtain information from successful Respondents to determine whether or not consolidation is required. If SDG&E determines that consolidation is required, SDG&E shall require the following during every calendar quarter for the term of an Agreement:

a) Complete financial statements and notes to financial statements, and financial schedules underlying the financial statements, all within 15 days of the end of each quarter.
b) Access to records and personnel, so that SDG&E's independent auditor can conduct financial audits (in accordance with generally accepted auditing standards) and internal control audits (in accordance with Section 404 of the Sarbanes-Oxley Act of 2002).

**Procurement Review Group and Independent Evaluator**

In D.02-08-071 (p. 24), the CPUC established the Procurement Review Group (PRG), whose members, subject to an appropriate non-disclosure agreement, would have the right to consult with and review the details of each utility's procurement plan, overall procurement strategy, contracts, and related matters. Since that time, the PRG process has been endorsed and continued in a variety of subsequent decisions, as it performs a valuable consultative role in the IOUs' procurement activities, including relating to the issuance and evaluation of RFOs and their results.[10] Thus, from RFO language development to Offer evaluation to contract negotiation, SDG&E will brief the PRG on a periodic basis during the entire process.

Respondents are hereby notified that revealing Offer information to the PRG is required during PRG briefings in accordance with Section 11.0 Confidentiality. Respondents must clearly identify, as part of the Offer, what type of information it considers to be confidential.

In D.04-12-048, the Commission ordered, in certain instances, the use of Independent Evaluators (IE) in competitive solicitations. SDG&E will make use of an IE in this solicitation. All Offer material produced in this solicitation will be available, under confidentiality provisions, to the IE. SDG&E in its sole discretion may make available to its PRG each response to this RFO and may review the results of its evaluation and ranking of the proposals with the IE and PRG.

## 11. Credit Terms and Conditions

SDG&E has the unilateral right to evaluate and determine the ability of the Respondent to perform relative to this project. The shortlisted Respondents will be required to complete, execute, and submit a credit application. This form is available to Respondents on the RFO website. The application requests financial and other relevant information needed to demonstrate and confirm creditworthiness.

Upon execution of a mutually acceptable definitive agreement, the Respondent will be required to post collateral based on the credit requirements established by SDG&E. For new development, Respondents will be required to post development collateral until commercial operation has been met. Collateral will be required during delivery periods for new and existing projects.

The table below presents the collateral amounts (cash or letter of credit) required for each product type should a contract be executed and depending on quantity. All Offers must include the cost of collateral in the amount required below in their Offer price.

[10] See, e.g., D.02-10-062, D.03-12-062, and D.04-12-048.

| Product | Collateral per 50 MW ($mm) |
|---|---|
| Product 1* | 1.7 |
| Product 2 | 25.6 |
| Product 3 | 5.5 |
| Product 4 | 5.5 |
| Product 5 | 25.6 |
| Product 6 | 25.6 |
| Product 7a (delivery years) | |
| 2010-2013* | 16.2 |
| 2010-2011* | 7.3 |
| 2012-2013* | 8.9 |
| Product 7b (delivery years) | |
| 2010-2013* | 1.0 |
| 2010-2011* | 0.4 |
| 2012-2013* | 0.5 |
| | ** Collateral per 10MW* |

Credit support amounts shall not be deemed a limitation of liability. Model credit support documents will be provided to shortlisted Respondents as applicable.

Under no circumstance will SDG&E post collateral for any resultant contract.

## 12. Proposal Costs

SDG&E will not reimburse Respondents for any of their expenses for developing responses hereto under any circumstances, regardless of whether the RFO process proceeds to a successful conclusion or is abandoned by SDG&E in its sole discretion.

## 13. Contingencies

1. CPUC Review and Approval. Any agreement entered into by SDG&E and a selected Respondent for Products 1, 2, 5 and 6 will be subject to and contingent upon (at a minimum) (1) the issuance by the CPUC of a final decision acceptable to SDG&E, approving such agreements and that does not materially alter the commercial aspects of the agreements; (2) a finding by the CPUC that the payments under the agreements are reasonable; and (3) a finding that SDG&E is authorized to recover the full amount of its costs including any payments made to Respondent under any of such agreements from SDG&E's customers in rates through existing or future cost recovery mechanisms that may be developed or instituted by the CPUC.
2. FERC Approval. In addition to the approvals required elsewhere in this RFO and the applicable agreement between the parties, SDG&E, in its sole discretion, may obtain and/or require Respondent to obtain: (1) a FERC order, as may be required, accepting and/or

authorizing any agreement(s) entered into hereunder, including without limitation, on terms that do not materially alter the commercial aspects of the agreement(s); and/or (2) a finding by the FERC that the rates, terms, and conditions are just and reasonable.

## 14. RESERVATION OF RIGHTS

SDG&E makes no guarantee that a contract award shall result from this RFO. SDG&E reserves the right at any time, at its sole discretion, to abandon this RFO process, to change the basis for evaluation of Offers, to terminate further participation in this process by any party, to accept any Offer or to enter into any definitive agreement, to evaluate the qualifications of any Respondent or the terms and conditions of any Offer, or to reject any or all Offer, all without notice and without assigning any reasons and without liability of Sempra Energy, SDG&E, or any of their subsidiaries, affiliates, or representatives to any Respondent. SDG&E shall have no obligation to consider any Offer.

## 15. Supplemental Information

SDG&E reserves the right to request additional information from individual Respondents or to request all Respondents to submit supplemental materials in fulfillment of the content requirements of this RFO or to meet additional information needs of SDG&E. SDG&E also reserves the unilateral right to waive any technical or format requirements contained in the RFO.

## 16. WAIVER OF CLAIMS AND LIMITATION OF REMEDIES

SDG&E will not reimburse Respondents for their expenses under any circumstances, regardless of whether the RFO process proceeds to a successful conclusion or is abandoned by SDG&E at its sole discretion without any resultant contract executed for any of the products.

SDG&E reserves the right to disregard a non-conforming Offer or waive requirements for any product and shortlist a non-conforming Offer.

By submitting an Offer, Respondent knowingly, voluntarily, and completely waives any rights under statute, regulation, state or federal constitution, or common law to assert any claim, complaint, or other challenge in any regulatory, judicial, or other forum, including without limitation, the CPUC, (except as expressly provided below), the FERC, the Superior Court of the State of California ("State Court") or any U.S. District Court ("Federal Court") concerning or related in any way to the RFO or any documents in the RFO including all exhibits, attachments, and appendices thereto ("Waived Claims"). Respondent further expressly acknowledges and consents that if it asserts any Waived Claim at the CPUC, FERC, State Court, or Federal Court, or otherwise in any forum, to the extent that Respondent's Offer has not already been disqualified, SDG&E is entitled to automatically disqualify such Offer from further consideration in the RFO or otherwise, and further, SDG&E may elect to terminate the RFO.

By submitting an Offer, Respondent further agrees that the sole forum in which Respondent may assert any challenge with respect to the conduct or results of the RFO is at the CPUC. Respondent further agrees that: (1) the sole means of challenging the conduct or results of the RFO is a complaint filed under Article 3, Complaints and Commission Investigations, of Title 20, Public Utilities and Energy, of the California Code of Regulations, (2) that the sole basis for any such protest shall be that SDG&E allegedly failed in a material respect to conduct the solicitation in accordance with the RFO; and (3) that the exclusive remedy available to Respondent in the case of such a protest shall be an order of the CPUC that SDG&E again conduct any portion of the solicitation that the CPUC determines was not previously conducted in accordance with the RFO or any RFO documents (including exhibits, attachments, and appendices). Respondent expressly waives any and all other remedies, including, without limitation, compensatory and/or exemplary damages, restitution, injunctive relief, interest, costs and/or attorneys' fees. Unless SDG&E elects to do otherwise in its sole discretion, during the pendency of such a protest the RFO and any related regulatory proceedings related to the RFO will continue as if the protest had not been filed, unless the CPUC issues an order suspending the RFO or SDG&E has elected to terminate the RFO.

Respondent further acknowledges and agrees that if Respondent asserts any Waived Claim, SDG&E shall be entitled to seek immediate dismissal of Respondent's claim, complaint, or other challenge, with prejudice, by filing a motion to dismiss (or similar procedural device) supported by the language in this Section and that Respondent will not challenge or oppose such a request for dismissal. Respondent further acknowledges and agrees that if it asserts any Waived Claim, and if SDG&E successfully has that claim dismissed or transferred to the CPUC, Respondent shall pay SDG&E's full costs and expenses incurred in seeking such dismissal or transfer, including reasonable attorneys' fees. By submitting an Offer, Respondent acknowledges and agrees that it has submitted that Offer after consultation with its own independent legal counsel.

Respondent agrees to indemnify and hold SDG&E harmless from any and all claims by any other Respondent asserted in response to the assertion of any Waived Claim by Respondent or as a result of a Respondent's protest to a filing at the CPUC resulting from the RFO.

Except as expressly provided in the RFO documents, nothing herein, including Respondent's waiver of any Waived Claims as set forth above, shall in any way limit or otherwise affect the rights and remedies of SDG&E.

## 17. Attachments

The following are available for download at the RFO Website:

1. The RFO

2. Technical Bid Forms (the form applicable to the product being offered is required)
   - Product 1
   - Product 2
   - Product 3
   - Product 4
   - Product 5
   - Product 6
   - Product 7a
   - Product 7b

3. Proforma Agreements – Respondents must include as part of the Offer redline comments to the applicable proforma agreement.
   - Tolling Agreement (required for Products 2, 3, 4, 5, 6)
   - EEI Firm LD Agreement (required for Product 7a)
   - WSPP RA Agreement (required for Product 7b)

4. Credit Application (required for all Products)
5. DBE Subcontracting Commitment And Reporting Requirements Form (required for Product 1)
6. Participation Summary (required for all Products except Product 1)

Respondents are encouraged to provide supplemental information to expand upon any unique capabilities to meet SDG&E's needs.

## Addendum

### Introduction to SDG&E: Background

San Diego Gas & Electric Company (SDG&E) provides electric service to approximately 1.3 million customers in San Diego County and the southern portion of Orange County. SDG&E also provides natural gas service to approximately 775,000 gas customers. The electric customer base comprises 89% residential and 11% commercial and industrial customers.

SDG&E's electric transmission network is comprised of 130 substations with approximately 884 miles of 69-kV, 265 miles of 138-kV, 349 miles of 230-kV, and 215 miles of 500-kV transmission lines. Major ("on system") generating resources are the Cabrillo plant (connected into SDG&E's grid at 138 kV and 230 kV), the South Bay plant (connected at 69 kV and 138 kV), the Palomar Energy Center (connected at 230 kV), the Otay Mesa plant (expected online in fall of 2009), a number of combustion turbine facilities located around the service area (connected at 69 kV), various Qualifying Facilities and renewable generation. Imported resources are received via the Miguel Substation as the delivery point for power flow on the Southwest Power Link, which is SDG&E's 500-kV transmission line that runs from Arizona to San Diego along the U.S./Mexico border, and via the SONGS 230-kV switchyard.

Figure 1 shows a simplified diagram of existing SDG&E service area and the electric transmission topology in San Diego County and the southern portion of Orange County. [11] Planned or approved transmission facilities for the future (if any) are not shown on this map. Upon completion of the Sunrise Powerlink (expected in 2012), the California ISO has proposed that it may expand their defined local area for SDG&E's transmission system. If the local area is expanded, there will be additional facilities and areas that will be considered local to the SDG&E transmission area.

Local Capacity Requirements are set by the California Independent System Operator ("CAISO") each year for the following year. Areas of Local Resource Adequacy correspond to the areas of Local Capacity Requirements as described in the 2010 Local Capacity Area Technical Study ("Technical Study" or "LCR Study"). This study is performed to identify specific areas within the CAISO Controlled Grid that have local reliability needs and to determine the minimum generation capacity (MW) that would be required to satisfy these local reliability requirements, while enforcing generation deliverability status and Maximum Import Capability for all common mode contingencies as defined by CAISO.[12]

The future area of Local Resource Adequacy has been projected by SDG&E based upon the 2011-13 Local Capacity Technical Analysis Report and Study Results published by CAISO on December 29. 2008 (http://www.caiso.com/20ad/20ad77d04d70.pdf).

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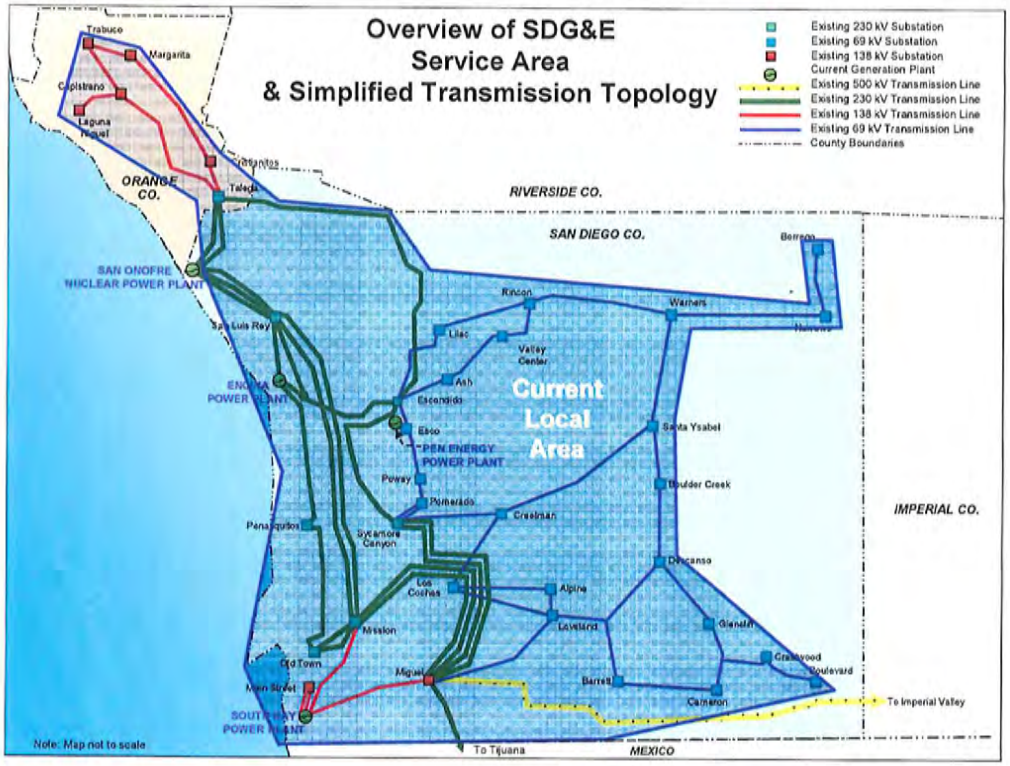
[11] SDG&E cautions that interconnection with the 500-kV Southwest Power Link or the Imperial Valley 500/230-kV Substation are not acceptable delivery points for proposals under this RFO because the reliability resource requirement is based on a contingency condition with the SWPL out of service. Similarly, direct interconnection to the San Onofre switchyard or the 230-kV lines from San Onofre to either Talega Substation or San Luis Rey Substation are not acceptable for the purpose of this RFO because these network facilities are fully utilized for the reliability condition of concern.

[12] 2010 Local Capacity Technical Analysis, Final Report and Study Results . California Independent System Operator, May 1, 2009.

## Figure 1. Current SDG&E Local Area



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April 13, 2012

Gary Chandler
Apex Power Group, LLC
2542 Singletree Lane
South Jordan, UT 84095

**Subject: Pio Pico Project – Comparative Construction and O&M Cost Analysis**

Dear Mr. Chandler:

E3 Consulting, LLC (E3) was requested by Apex Power Group, LLC (Apex) to prepare an independent evaluation of the costs to build and operate a nominal 300 MW power generation facility using three different generation technology options. The three options include:

- GE LMS100PA, three units in simple-cycle (SC) configuration;
- GE Frame 7FA.04 Fast Start in 1x1 combined-cycle (CC) configuration, and;
- Siemens SCC 5000F Flex 10 1x1 combined-cycle configuration.

E3 is a technical advisory firm that specializes in providing independent engineering reviews to support the development, financing or acquisition of electric power generation and electric transmission facilities. E3 provides services to regulatory agencies, government agencies, lenders, investors and developers of energy facilities. Prior to this assignment, E3 has had no involvement of the Pio Pico project being proposed by Apex.

In conducting the analysis, E3 has relied upon its experience reviewing nearly 600 power generation facilities in the U.S. and worldwide. This experience includes conducting other independent reviews of projects using or proposing to use the three technologies listed above. E3 has also reviewed publicly available information regarding costs to develop, construct and operate power generation facilities using the same or similar technologies to those listed above.

## Analysis Overview

For the purposes of this analysis E3 was provided with certain assumptions by Apex regarding the design and expected operations of the Pio Pico generating facility. These principal assumptions include:

- The project will be located in San Diego County, CA and will sell its net electrical capacity and energy to San Diego Gas & Electric Company (SDG&E);
- The project will use natural gas only for fuel;
- All three options will include conventional Oxidizing and SCR catalyst systems for CO and NOx control. The LMS100 option will also include water injection for emis-

sions control. The Siemens Flex 10 system also uses steam injection for power augmentation.
- The project will operate at base load for 4000 hours per year with an estimated 500 dispatched starts by SDG&E;
- Construction will be performed under a typical turn-key Engineering, Procurement and Construction (EPC) type agreement.
- Operations and Maintenance (O&M) will be provided by a third-party contractor under a market based O&M Agreement. Major maintenance of the prime mover equipment will be by the original equipment manufacturers under the terms of a typical Long-Term Service Agreement (LTSA).

Based on our review of other similar projects and review of published information regarding construction and O&M costs of similar facilities, E3 estimates the following capital and O&M costs for the three technology options.

**Table 1**
**Construction and O&M Costs for**
**Three Generation Options**

| Primary Technology | Cycle | Net Output | Capital Cost | Fixed O&M | Var O&M (non major) | Major Maint |
|---|---|---|---|---|---|---|
| **LMS100PA-SAC** | 3x0 SC | 310 MW | $829/kW | $15.3/kW-yr | $0.91/MWh | $2.09/MWh |
| **GE 7FA.05** | 1x1 CC Fast Start | 312 MW | $1,029/kW | $16.1/kW-yr | $0.85/MWh | $2.35/MWh |
| **Siemens SGT6-5000F** | 1x1 CC Flex 10 | 279 MW | $1,153/kW | $16.1/kW-yr | $0.85/MWh | $4.56/MWh |

The following specific assumptions were made when estimating the numbers presented in the table above:

- Estimated capital costs are in 2012 dollars and are for the basic power block and balance of plant equipment. Costs include interest during construction, but do not include long-term amortization costs.
- Costs are US average do not include site specific costs such as power and gas interconnections, permitting, emissions offsets, land acquisition or adjustments for southern California construction labor costs conditions.
- The base capacity ratings and construction costs have been adjusted for dry or hybrid cooling. Cooling requirements for the CC options are significantly greater than the LMS100 option due to the need for a steam turbine condenser. Capital costs for air cooled condensers on the CC options will increase the CC capital costs by approxi-

mately $30 million compared to a conventional wet evaporative cooling system. The additional costs for dry cooling are included in the table above.

- Fixed O&M costs include O&M contractor costs such as labor, administration, fixed consumables and home office expenses.
- Owner costs such property and liability insurance, property taxes and asset management are not included.
- Variable O&M expenses include consumables, chemicals, routine preventative maintenance and inspections.
- Major maintenance includes major overhauls and parts replacements conducted at scheduled intervals by the OEM in accordance with a LTSA.
- Major maintenance expenses are based on recent OEM quotes for full LTSA services through a typical 50,000 hour major combustion turbine overhaul cycle. Estimated LTSA costs are based on typical Factored Fired Hour (FFH) pricing for scheduled services. The FFH pricing for the CC options are adjusted to the expected ratio of FFH to Factored Fired Starts (FFS) in accordance with GE and Siemens guidelines. The LMS100 combustion turbine technology does consider the number of starts when calculating FFH.

## Comments and Observations

1. The combined-cycle facilities are estimated to cost approximately 30 percent more to build than the simple-cycle option. This is due to the greater balance of plant requirements for the steam cycle, significantly larger cooling system (for the steam turbine condenser), higher construction man-hours (boiler erection and steam cycle piping) and greater land requirements. The GE Fast-Start CC option requires an auxiliary boiler to maintain the steam cycle in warm standby condition to allow for 400-minute rapid response. The Siemens Flex-10 CC and LMS100 simple-cycle options do not require an auxiliary boiler to operate during standby periods.
2. The fixed O&M costs for the CC options are slightly higher due to larger staffing requirements to operate auxiliary steam systems and maintain boiler water chemistry on a 24/7 basis.
3. Simple-cycle plants can typically be constructed in 12-16 months. Combined-cycle facilities typically require at least 24 months to build and commission.
4. Simple-cycle configurations do have higher heat rates and emissions per MWh than typical CC configurations, but use less fuel during startup, shutdown and non-operating standby periods.
5. The fast-start CC configurations included in this analysis achieve faster full-power operations (typically 1.5 to 2.0 hours to full load) by using control strategies to shorten the initial gas purge cycle, maintaining turbine lube oil and boiler water at high temperature and using simplified (non-reheat) and lower pressure steam cycles to reduce the thickness of boiler tubing and steam turbine shells (and therefore reduce the

warm up time). These design compromises for fast start capability result in net heat rates for fast-start CC cycles that can be up to 10 percent higher than conventional modern CC cycles that use multi-pressure reheat steam cycles.

6. The GE LMS100 technology was specifically designed for the rapid response peaking market. Over 30 units are in operation and the technology has a proven track record of being capable of full power output within 10 minutes of start initiation.
7. There currently are no GE Fast-Start or Siemens Flex 10 CC cycles with more than one year of operation to demonstrate the capability or efficiency of the cycles. At this time E3 does not consider the GE or Siemens fast start CC plant designs to be commercially proven technology.
8. The CC options will suffer potentially significant major maintenance cost penalties compared to the LMS100 due to the low ratio of FFH to FFS. Based on the assumed 4000 annual operating hours and 500 annual starts the FFH/FFS ratio will be 8. Typically CC projects are intended to run as intermediate to base load units with FFH/FFS ratios of 25 or higher. Due to the frequent starts and low number of operating hours between starts, maintenance on the combustion turbines, heat recovery steam generators and steam turbines is greatly accelerated as a result of rapid thermal cycling. Estimated major maintenance costs are based on actual GE and Siemens OEM long-term service agreements for conventional CC plants which include pricing adjustments based on the ratio of fired hours to starts.
9. Based on our prior reviews of numerous simple-cycle and combined-cycle combustion turbine plants, we are of the opinion that for peaking and intermittent operations, simple-cycle plants are generally better suited because of lower capital and maintenance costs, lower cooling water requirements and low auxiliary power and fuel requirements during standby periods.

Please do not hesitate to contact me if there are any questions related to our analysis or assumptions.

Best Regards,
***E3 Consulting***

Paul B. Plath

Paul B. Plath, P.E.
President

# Exhibit 3

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

| | | |
|---|---|---|
| | ) | |
| **Standards of Performance for** | ) | **Docket No. EPA-HQ-OAR-2011-0660** |
| **Greenhouse Gas Emissions for** | ) | |
| **New Stationary Sources: Electric** | ) | *Via regulations.gov* |
| **Utility Generating Units** | ) | *June 25, 2012* |
| | ) | |

Thank you for accepting these comments on EPA's proposed Standards of Performance for Greenhouse Gas Emissions for Stationary Sources; Electricity Utility Generating Units ("EGU NSPS"), 72 Fed. Reg. 22,392 (Apr. 13, 2012).

We submit these comments on behalf of Sierra Club, Environmental Defense Fund, Natural Resources Defense Council, Earthjustice, National Wildlife Federation, Environmental Law and Policy Center, Southern Environmental Law Center, and Clean Air Council ("Joint Environmental Commenters").

## I. Introduction

As EPA has properly concluded, the scientific record demonstrating that "elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future U.S. generations is robust, voluminous, and compelling."[1] Electric generating units (EGUs) are the single largest source of domestic greenhouse gas emissions. Accordingly, as we discuss at length below, EPA must control greenhouse gas pollution from this source category under section 111 of the Clean Air Act, 42 U.S.C. § 7411. Indeed, unless emissions from new and existing power plants are reduced, the United States will be unable to prevent or mitigate serious harm from climate change.

In this introductory section, we briefly describe some of the harms associated with greenhouse gas emissions and show why the emissions profile of the EGU sector demands expeditious regulation under section 111.

[1] 75 Fed. Reg. 49,556, 49,557 (Aug. 13, 2010) (Endangerment Reconsideration Denial), attached as **Ex. 1;** *see also* 74 Fed. Reg. 66,496, 66,523 (Dec. 15, 2009) (Endangerment Finding), attached as **Ex. 2**.

As the Agency has noted previously, the NSPS does not protect high-polluting processes:

> For some classes of sources, the different processes used in the production activity significantly affect the emission levels of the source and/or the technology that can be applied to control the source. For this reason, the Agency believes that the 'best system of emission reduction' includes the processes utilized and does not refer only to emission control hardware. It is clear that adherence to existing process utilization could serve to undermine the purpose of section 111 to require maximum feasible control of new sources. In general, therefore, the Agency believes that section 111 authorizes the promulgation of one standard applicable to all processes used by a class of sources, in order that the standard may reflect the maximum feasible control for that class.

Standards of Performance for New Stationary Sources, Primary Copper, Zinc, and Lead Smelters, 41 Fed. Reg. 2332, 2333-2334 (Jan. 15, 1976).

### 4. Treatment of Peaking Units and Simple-Cycle Gas-Fired Units

EPA has asked for comment on the treatment of simple cycle natural gas-fired units that are currently within Category KKKK, and which EPA has proposed not to include in Category TTTT. EPA specifically requested comment on the option of excluding from Category TTTT facilities with permit restrictions limiting operation to less than 1/3 of their potential electric output, or approximately 2,900 hours of full load operation annually.

#### a. Distinctions Among Fossil Fuel-Fired Power Plants Should Be Based on Function Rather than Purpose or Technology.

Joint Environmental Commenters strongly support EPA's decision to combine fossil fuel-fired sources into one category, but we do not support EPA's blanket exclusion of all new simple cycle natural gas-fired units from the category. EPA has failed to justify excluding simple cycle units from any performance standard for GHG emissions. Indeed, there are compelling reasons for including all fossil fuel power plants that provide electricity to the grid in the same category. These units share the same broad function and they are operated as an integrated system.

If a distinction is needed between a peak-load unit and an intermediate-load or baseload unit, that distinction should be made on a functional, objective criterion – *e.g.*, a legally-enforceable limit on how a unit is used – not on the basis of technology type or statements of the owner's or operator's purpose in constructing it. Insofar as EPA proposes to distinguish peaking units from baseload and intermediate- load units, true peakers can be effectively distinguished by an enforceable hours-of-operation limit, and a standard of performance can be rationally tailored to their limited utilization, rather than by categorically excluding all simple-cycle turbines or referring to the "purpose" for which units are constructed. As we discuss below, any such new units used for more than 2000 hours per year[85] should be considered to be serving baseload or intermediate load demand, and should be subject to the same emission limit as other new plants serving such load. To the extent that EPA concludes that peaking units should not be subject to the same standard, EPA should promptly set a separate appropriately tailored standard of performance in a supplementary rulemaking, but should not delay finalizing this rule.

This approach would preserve the option of prospective owners and operators to select designs that fit their expected patterns of use. If the builder of a new combustion turbine wants the option to use the unit for more than peaking purposes, it can add a heat recovery steam generator, for example, to increase the unit's efficiency and reduce its emission rate below the standard (turning the unit into an NGCC). This approach is a cost-effective emission control strategy for units designed to operate more than 2,000 hours per year.

There are several additional advantages to relying on a functional definition of intermediate-load and baseload EGUs, rather than including a categorical exclusion based on a particular technology. First, while market conditions make it unlikely that any new simple cycle combustion turbines would be built for use more than 2,000 hours per year, if such units were so operated there would be significant public health and environmental benefits to requiring them to comply with the proposed standard. Second, a functional approach is more robust in the face of unanticipated technological developments, which, for example, could make simple cycle turbines an economical option for intermediate-load operations – in which case they should be subject to the best system of emission reduction identified for sources serving that purpose. Finally, including an unnecessary categorical exemption from the proposed standard only serves to create the possibility that generators would seek ways to evade the standard by finding ways to qualify for that exemption.

[85] Our proposal below, includes a limit on daily hours or operation. Here we employ a short hand "2000 hours per year" to facilitate discussion of this recommendation.

### b. The Definition of Electric Generating Unit Does Not Serve to Distinguish Peaking Units from Intermediate-Load and Baseload Units.

EPA has proposed the following definition of electric generating unit:

> *Electric utility generating unit* or *EGU* means any steam electric generating unit or stationary combustion turbine that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale.

This definition raises several concerns with regard to the possibility of using it to address peaking units. As an initial matter, any definition that relies solely on the "purpose" of a unit will be difficult, if not impossible, to enforce, especially if market conditions lead an operator to "repurpose" a unit after construction. EPA should revise this definition to provide for more objective criteria for defining an EGU. Further, EPA has not provided any rationale for its proposed use of the "**potential**" electric output of a unit or the reason why "one-third of the potential electric output" should differentiate between EGUs and non-EGU units. While this definition may not have been problematic in the past, the adoption of the proposed $CO_2$ emission limits may create significant new incentives for coal or gas units to circumvent the rules.

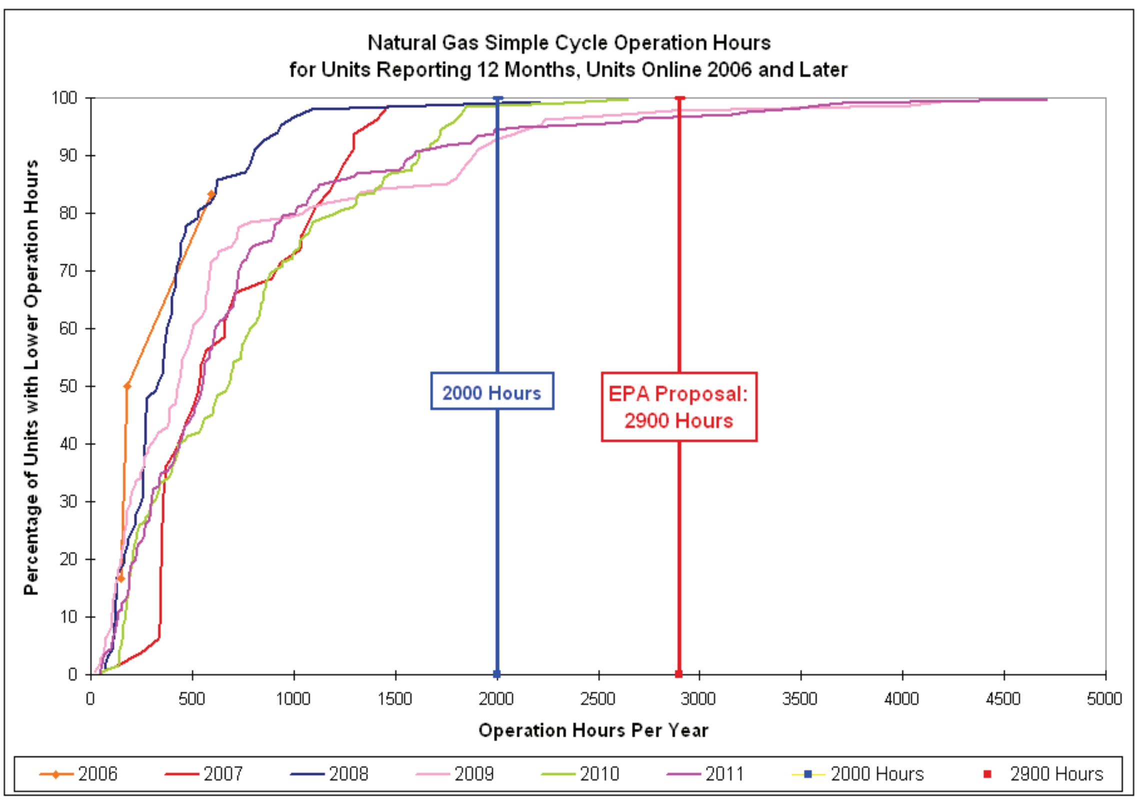
We note that peaking units and even intermediate-load units are built with the purpose of supplying less than one third of their potential electric output to the grid. Peaking units ordinarily have capacity factors of less than 15 percent and intermediate load NGCC units may operate for relatively few days per year so that their electric output is less than the proposed 33 percent of potential output. Further, such units may, and often do, operate at less than full load – an intermediate load unit could operate at 60 percent load factor for half of the year and still not generate 33 percent of its potential electric output capacity. Joint Environmental Commenters therefore strongly urge EPA to change the EGU definition to eliminate this significant loophole.[86] By limiting the sources included in the category to only those that supply more than one-third of their *potential electric output capacity* to the grid, EPA would exclude units that operate at a significant capacity for a significant portion of the year (e.g. 60 percent capacity for half the year). Such units are intermediate load rather than peaking units and should be subject to this standard. We believe this problem may be remedied if the definition is clarified so that a source is an EGU **if at any time** it provides more than one-third of its rated name plate energy capacity to the grid.

[86] We further suggest that EPA could accomplish its goal of providing separate treatment of peakers by defining EGUs without any reference to peakers, so that peakers remain in category TTTT, but by amending proposed section 60.5520(d) to provide a separate standard for peakers, defined using the approach we advocate above.

### c. The Data Suggest that Simple Cycle Units Are Not Only Used to Serve Peak Power and that Peaking Units Are Those that Operate No More than 2000 Hours per Year.

The available data show that almost all simple cycle combustion turbine ("CT") units have low operating hours – but they also appear to show that there are a number of large CT units with high capacity factors. As discussed above, EPA should not use the definition of electric generating unit to define peaking units because this suggestion leaves open the possibility of intermediate-load units operating at less than rated capacity for long periods of time being classified as peaking units. EPA has suggested that an alternate approach might be to establish a limit on the annual hours of operation of peaking units. We agree that an enforceable hour of operation limit is part of an appropriate alternative approach, but the histogram in Figure 1 shows that EPA's suggested 2900 hours is too high. The "knee in the curve" for these data appears to be below 2000 hours for 2011 (the most favorable[87] year for industry), thus showing that operation greater than 2000 hours is not consistent with the normal operation of CTs.

<u>Figure 1. Hours of Operation for Combustion Turbines, by Year</u>[88]

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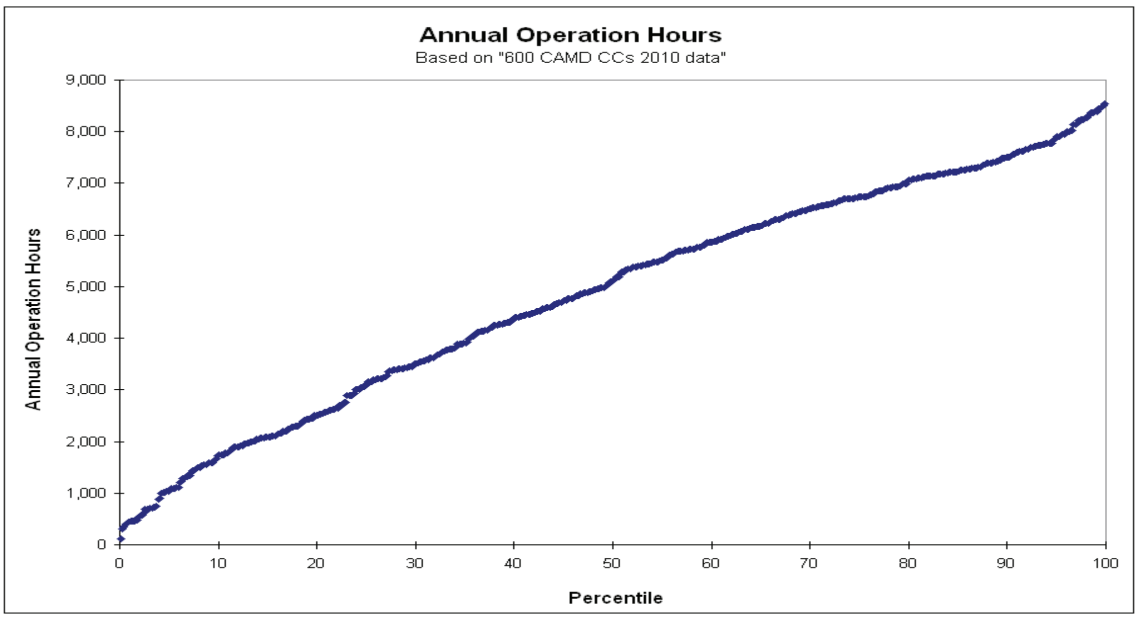
[87] For 2008, it is closer to 1100 hours.

[88] First year of operation 2006 or later, as determined by earliest occurrence of CAMD CEMS data. This data is included in Appendix D.

We note that even 2000 hours of operation may represent CTs that are in intermediate load rather than peaking operation, especially if such use is seasonal. We also note that there are a substantial number of combined cycle units that are designed for intermediate load applications but that may have limited hours of operation because of market conditions. Eighty-two of the 592 recently constructed combined cycle units in the EPA CAMD data set, Figure 2, operate less than 2000 hours per year; 143 of those units operated less than 2900 hours per year.

Figure 2. Hours of Operation for Combined Cycle Units




These data suggest that an hour of operation test is needed, but that such a test, standing alone, does not sufficiently differentiate peaking from intermediate-load units that may operate seasonally, but for many hours at a time once started up. Such units are seasonal or load following, properly classified as intermediate load units. These units are not true peaking units and are within the functional category defined by EPA. Here, industry practice provides what appears to be the most useful definition of a peaking unit. General Electric defines “peaking” units in terms of an average hour of operation per startup. GE Performance defines base load as operation at 8,000 hours per year with 800 hours per start. It then defines peak load as operation at 1250 hours per year with five hours per start.[89] We urge EPA to include an hour per operating day

[89] Brooks, F., GE Power Systems, *GE Gas Turbine Performance Characteristics, GER-3567H*, p.14, accessed at

limit as well as an annual hours of operation limit in its definition of peaking units to (1) properly define peaking units and (2) ensure that, if simple cycle CTs are used as base load or intermediate load units, the emission limits associated with those functions apply. To provide operators with a measure of flexibility, while still distinguishing between seasonally operated intermediate-load units and peaking units, we recommend that the GE norm of 1250 hours per year be relaxed to 2000 hours per year and that the 5 hours per start definition be modified to an 8 hour per operating day limitation, established on a 30-day rolling average basis. EPA should establish the annual hour of operation limit on a rolling annual basis, with the calculation rolled daily.

### 5. Treatment of CHP Units

Under EPA's proposal a unit is not an EGU unless more than one-third of its potential generating capacity is intended to be sold to the grid. Thus, many combined heat and power units (whether coal, oil or natural gas-fired) would be exempt from EPA's proposed rules. However, based on the perceived environmental benefits of CHP, EPA has requested comment on allowing such units to be exempt even if they sell up to 80 percent of their useful output as electricity to the grid. This would seem to be a dangerous incentive for EGUs to avoid the strictures of the rule by partnering with smaller industrial operations. The likely result of the exemption EPA is considering would be substantially increased GHG emissions with no countervailing environmental benefit. Joint Environmental Commenters therefore strongly oppose exempting CHP units if more than one-third third of their potential generating capacity is intended to be sold to the grid.

EPA has also solicited opinion about how to account for CHP emissions. The EPA proposal would allow CHP units to count 75 percent of their thermal output as part of their gross output used to calculate their emission rate in demonstrating compliance. However, the more appropriate way to recognize the potential environmental benefits of CHP is to appropriately account for the emissions associated with useful thermal output. We believe that it makes more sense to deduct the $CO_2$ emissions from CHP units that is associated with their other uses of a portion of the energy created, rather than adding a "theoretical" electric generation (representing the amount of electricity that would have been generated by steam used onsite) to their output. Both approaches have a similar result—the effective emission rate for CHP units is reduced for compliance purposes. However, it is more appropriate to assign the emissions associated with producing used thermal output to the sector where that thermal energy is used (which is outside the scope of this standard) than it is to assign theoretical additional electric output to CHP units based on their thermal output. The emissions to be deducted should be calculated by determining the emissions that would have been

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http://www.muellerenvironmental.com/documents/GER3567H.pdf

# Exhibit 4

April 17, 2013

**Via Email and Certified U.S. Mail**

Marc Crooks
Air Quality Department
Washington Department of Ecology
P.O. Box 47600
Olympia, WA 98504-7600
mcro461@ecy.wa.gov

**RE:** Fredonia Power Generating Station –Permit No. PSD-11-05

Dear Mr. Crooks:

These comments are submitted on behalf of Sierra Club and its 600,000 members, including over 21,000 members in Washington. The issues addressed below regarding the proposed Prevention of Significant Deterioration (PSD) permit for Puget Sound Energy's (PSE) Fredonia Power Generating Station (PSD-11-05) are based off of the January 30, 2013 Technical Support Document (TSD) prepared by the Washington State Department of Ecology Air Quality Program (Ecology) and the proposed permit.

Sierra Club appreciates the opportunity to provide these comments to ensure that any electric generating units planned for construction at the Fredonia site are consistent with the most rigorous air quality pollution control measures required by law. As a preliminary matter, Sierra Club notes that the permit application and the TSD lack documentation for several critical assertions needed to establish appropriate permit terms and conditions. This omission is a major concern throughout the application and the TSD for the proposed permit. For example, Ecology copies PSE's Table 5-5 into the TSD as Table 14 and includes calculations that are neither sourced nor critically reviewed by Ecology. This lack of supporting data impedes meaningful review by Ecology or the public. Ecology should provide all worksheets in Excel or other accessible formatting to the public. Similarly, PSE's load forecasts and dispatch modeling must be provided to verify several critical operating assumptions for the proposed addition to Fredonia.

### 1. GHG BACT Requires a GHG Emissions Rate Limit Achievable by the Most Efficient Turbine Model

New construction projects that are expected to emit at least 100,000 tpy of total GHGs on a $CO_2$e basis, or modifications at existing facilities that are expected to increase total GHG emissions by at least 75,000 tpy $CO_2$e, are subject to PSD permitting requirements even if they do not significantly increase emissions of any other PSD pollutant. The proposed Fredonia facility would add one or two new generating turbines and is expected to emit GHGs at a rate greater than 100,000 tpy $CO_2$e; therefore, the project is subject to PSD review for all pollutants emitted in a significant amount.

PSE requests approval to construct one of the following four options:

- One (1) General Electric (GE) 7FA.05 frame turbine, rated at 207 MW
- One (1) GE 7FA.04 frame turbine, rated at 181 MW
- One (1) Siemens SGT6-5000F4 frame turbine, rated at 197 MW
- Two (2) 100 MW GE LMS100 aero derivative turbines (combined rating of 200 MW)

Ecology proposes to allow PSE to choose any of these four options, regardless of their relative greenhouse gas (GHG) emission rates. The proposed permit sets four different GHG emission rate limits for each option based on the heat rate at full load for each design. (TSD, Table 14 at p.34.) Ecology justifies this approach of setting different emission limits because the permit also sets different maximum fuel use limits for each turbine design – and therefore the annual tons-per-year of GHG emissions – differs (i.e. the most efficient unit has the highest maximum fuel use limit).[1] However, this approach is not appropriate because it confounds a maximum limit on the potential to emit with the BACT emissions rate analysis.

This proposal does not comply with PSD permitting requirements because the relative efficiency of the four turbine designs is different, and therefore the GHG emission rates are different. Ecology cannot set different emission limits for whichever turbine design the applicant chooses, as the draft permit purports to do, because the emission reduction achievable through a clean production process is part of the BACT definition. Rather, the most efficient turbine design must be used as the basis for the BACT limit unless the applicant demonstrates a sufficient site-specific basis to reject that technology. Here, the applicant cannot make this claim, and, in fact, PSE indicates that it may choose to use the most efficient turbine technology. **The PSD permit must require PSE to meet a GHG emission rate (1,138 lb-$CO_2$e/MW-hr) that is achievable by the most efficient unit, the GE LMS100**.[2]

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[1] There is no support in the TSD for requiring different maximum fuel limits. PSE's application assumes, without explanation, that the LMS 100 units will run at a 33% capacity factor, excluding startup and shutdown, while other units run at a 26% capacity factor. In addition, the annual emissions are based on the "worst-case" operating scenarios that would result from the maximum operating limits. (TSD at p.7.) As a result, the comparison between different turbine design estimates of tons-per-year GHG emissions is distorted by the unequal worst-case operating scenarios.

[2] Proposed Permit at §V(D)(1)(a)(iv). The total limit is higher than the combustion turbine's $CO_2$ emission rate because Ecology incorporates emissions of $CH_4$ and $N_2O$ using the emission factors from previous source testing at PSE's Sumas and Mint Farm Generating Stations in 2009. (TSD at pp. 9 and 36.)

Clean Air Act § 165(a)(4) requires Fredonia to install the Best Available Control Technology (BACT), which is defined as "an emissions limitation … based on the maximum degree of reduction for each pollutant subject to regulation under the Act…" 42 USC 7479(3); 40 CFR 52.21(b)(12). Ecology recognizes that for GHG emissions, the efficiency of the combustion unit is a primary factor that determines GHG emission rates. "GHG emissions are directly related to minimizing the quantity of fuel required to make electricity." (TSD at p.32.) In this case, the $CO_2e$ emission rate of the LMS-100 design is 1,052 lb/MW-hr for the turbine. (TSD at p.33, Table 13.) The least efficient unit, the GE 7FA.04, has a $CO_2e$ emission rate that is 13.2% higher at 1,191 lb/MW-hr. This difference would roughly equate to 34,194 tons annually, assuming 2,000 operating hours (23% capacity factor) for each unit.[3]

a) <u>The Permit May Not Set a Weaker GHG Limit Based on Alternate Operating Scenarios.</u>

The LMS 100 units are clearly more efficient than all of the other simple-cycle turbine options contemplated by the proposed PSD permit. Ecology fails, however, to base its proposed BACT limit on the lowest GHG emission rate among the available options. Instead, Ecology concludes that all four options are BACT because "Ecology considered engine efficiency together with proposed operating scenarios associated [with] all four options during BACT analysis." (TSD at p.35.) There is no basis under the law for selecting a higher emitting technology based on different operating scenarios. The BACT requirement is defined as "the maximum degree of reduction for each pollutant." 42 USC 7479(3). PSE does not suggest that the LMS 100 units are infeasible or inconsistent with the purpose of the project. Since PSE states that the technologies that would meet its needs range from 185 to 215 MW,[4] the 199.7 MW LMS100 can meet that need. (TSD, Table 14, at p.34.) Therefore, the top-down BACT analysis requires Ecology to select the lowest emitting technology as the basis for setting the BACT emission limit. In this case, that technology either the LMS 100 or a fast start CCGT unit, such as those offered by GE and Siemens.

Ecology asserts that a weaker GHG emission rate limit for different turbines is appropriate because differences in annual operating scenarios and operating hours mean that "the least efficient make and model is not necessarily the highest annual emitting option." (TSD at p.35.) This conclusion is contrary to the BACT requirement that Ecology set the emissions limit based on the maximum degree of pollution reduction achievable. Ecology's approach conflates the issue of the BACT analysis with the issue of setting maximum operating limits under worst-case conditions. Changing the maximum operating scenarios for higher emitting units is not a valid justification for weakening the GHG emissions limit. Doing so would allow an applicant to alter its estimated operating hours to avoid a more stringent emissions limit and invite gaming of the BACT analysis. Here, the most efficient technology <u>**is**</u> the best available technology, and the BACT limit, in terms of lb $CO_{2e}$/MWh, must reflect this efficiency.

Ecology's contention that GHG emissions limit should be weakened because of net annual GHG impacts under different operating scenarios is also unsupported. The total annual fuel use

[3] Table 14 assumes a capacity factor of 7.5% and a corresponding $CO_2e$ tpy difference of 9,101 between the LMS 100 and the 7FA.04. Sierra Club's estimate of emission difference at 2000 hours (23% capacity factor) is derived from Attachment A.

[4] These figures reflect the most current ratings for the units identified in the TSD, as published in the 2011-2012 *Gas Turbine World Handbook,* published by Pequot Publishing, Inc. ("GTW Handbook")

of the LMS 100 is much higher than the other units, despite the fact that it is the most efficient unit. This skewed estimate is the result of the assumption that the LMS 100 would operate more hours than the other units. The record does not include load forecasts or dispatch modeling supporting the assumption that the various turbines would be operated differently, and the respective permit maximum limits do not require that the chosen turbine be operated according to these hypothetical scenarios. To the contrary, the calculations in Table 14 of the TSD assume that all of the turbine designs operate at a much lower 7.5% capacity factor. Ecology must explain why the LMS 100 turbine designs would practically operate so differently than the other turbine designs. In particular, Ecology must explain in much more detail how it derived the annual maximum fuel limits for each turbine design.

The Fredonia units will presumably be dispatched as needed based on their economic loading order.[5] Even if the LMS 100 units were dispatched more frequently or at greater generating capacities than the other options, it would be because of their higher efficiency compared to other resources. In other words, Ecology's theory undermines BACT because it assumes that the most efficient process is more competitive in the market and therefore operates more often, and emits more, and so should not be the basis for BACT. Even assuming that it is appropriate to consider how the plant will operate within the market, Ecology should not look only at this plant in such an analysis. Any increased operations of a more efficient technology chosen for this plant would likely displace generation from other, less efficient, peaking units within PSE's system.[6] In short, GHG emissions from peaking units in the PSE system as a whole will likely be lower if the LMS 100 models are employed as compared to the other units proposed. The LMS 100 units are the lowest emitting units on a per MW-hour basis, and therefore that technology must be considered as BACT for GHG.

b) <u>BACT Requires an Emissions Limitation Based on the Maximum Degree of Reduction Available.</u>

PSE's application argues that, "EPA has never taken the position that BACT requires an applicant to purchase a particular make and model of turbine engine for an electric generating facility."[7] This argument misses the point of the BACT requirements. BACT does not select a technology, it sets a limit. EPA (and other permitting agencies) may not require a specific make and model of technology, but that does not mean that a BACT limit does not affect the range of buying options available to a facility. The NSR Manual provides: "The reviewing authority…specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable…" (NSR Manual, p.B.2.) In this case, the maximum degree of reduction is a combustion turbine achieving 1,052 lb $CO_2$e/MW-hr. Turbine vendors that can meet that limit are free to compete for PSE's business. Just as a BACT limit for another pollutant may be based on the most efficient scrubber design, scrubber vendors who can achieve sufficient emission reductions can compete for that contract. This feature of the BACT program has been remarkably successful in encouraging development of more effective pollution controls for over 40 years.

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[5] Neither the permit nor the TSD discuss the results of any dispatch analysis. To the extent such a study informed the BACT analysis, it should be included in the TSD.

[6] It is possible that more efficient combined cycle units or renewables could be displaced, but there is no evidence in the application or the TSD suggesting that the proposed peaking units at Fredonia would ever displace lower-emitting units.

[7] Application, Appendix H, p. 5-16.

Furthermore, to the extent that Ecology implies that EPA does not establish BACT limits for GHGs based on turbine efficiency that might exclude some turbine designs, Ecology is incorrect. Turbine efficiency is clearly an important factor that EPA considers in its BACT analyses. The TSD identified the York Plant Holding project considered by Pennsylvania DEP. (TSD at p.33.) EPA Region 3 submitted the following comments on the proposed PSD permit: "The permit record should be able to show that the most efficient turbine model is chosen for the proposed project, or it should justify why a turbine with a lower efficiency was selected."[8] Similarly, Region 9's final PSD permit for the proposed Pio Pico Energy Center considered a proposed LMS 100 turbine design, concluding that "this [turbine efficiency] is at the high end of the efficiency range for gas turbines of this size category, thus we believe that the applicant's proposal is consistent with the BACT requirement to use highly efficient simple-cycle turbines."[9] It is entirely appropriate, and in fact necessary, to consider specific makes and model of turbine designs when determining the BACT emission rate limit.[10]

c) The TSD's Analysis of Incremental Emission Reduction Costs Does Not Comply with BACT Requirements.

The incremental cost difference between the different turbine options does not provide a reasonable basis to reject the lowest achievable GHG BACT emission limit. The TSD states, "The analysis shows that further $CO_2e$ reductions would cost between $710 and $4,660 per ton of $CO_2e$ removed." (TSD at p.34.) This calculation compares the relative $CO_2e$ emissions of all turbines operate at a 7.5% capacity factor to the overall fixed and variable cost of operating each unit at that capacity factor. Ecology then concludes that this cost range is "in excess of costs that have been considered 'achievable' in other GHG BACT analyses…" (TSD at p.34.) This conclusion fails to comply with the requirements for rejecting a feasible technology based on a determination of adverse economic impact.

Step 4 of the BACT analysis considers the energy, environmental, and economic impacts of each feasible control option. (NSR Manual, pp. B.26-B.53.) The presumption is that the highest ranked feasible control technology is the basis for the BACT limit unless there is a specific determination that cost and impacts borne by the specific source in question are disproportionately higher than other sources in the same category. (NSR Manual, p.B.29.) Ecology has not determined (nor could it determine) that the cost to use the most efficient turbine at the Fredonia plant is any more expensive, on a cost per ton basis, than any other facility using that technology.

Moreover, as noted in the TSD, several permitting agencies have determined that the most efficient natural gas turbine design is the appropriate basis for the GHG BACT limit. (TSD at pp.29-30.) For example, as noted above, in considering a simple cycle natural gas turbine for the York Plant Holding project, which Ecology specifically cited in the TSD (TSD at p.33), Pennsylvania DEP expressly found that the most efficient simple-cycle turbine is BACT: "Even though the applicant wants to retain the ability to purchase any of the three turbines for purposes

[8] November 1, 2011 Letter from Kathleen Cox (EPA Region 3) to William Weaver (Pennsylvania DEP), (available at: http://www.epa.gov/nsr/ghgdocs/20111101york.pdf ).

[9] PPEC Fact Sheet and Air Quality Impact Report, p. 20, (available at: http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2011-0978-0017). Sierra Club is currently appealing this permit to the Environmental Appeals Board.

[10] *See, EPA PSD and Title V Permitting Guidance for Greenhouse Gases,* March 2011, pp. 21, 29-30 (available at: http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf).

of maintaining a business advantage, in terms of heat rate, the GE LM6000 is the most efficient turbine and the GHG emission rates are developed based on the efficiency of that turbine."[11] The BACT determination for the York Plant Holding project rejected the approach that Ecology seeks to implement here: Pennsylvania DEP set the emission limit based on the most efficient turbine design rather than allowing the applicant to choose among several different GHG emissions limits for each design.

There is no evidence in the TSD or the application indicating that installing and operating the LMS 100 turbine design would cause uniquely excessive costs at Fredonia compared to other electric generating facilities. Ecology therefore has no basis to reject the most efficient and lowest GHG emitting turbine design based on adverse economic impacts.

a) The TSD's Analysis of Incremental Emission Reduction Costs is Unsupported and Incorrect

As noted above, the incremental cost analysis is not an appropriate reason to exclude the more efficient turbine design as BACT because there is nothing unique about the Fredonia facility that would make installation of the LMS 100 units disproportionately more expensive than at comparable facilities. However, even if the incremental cost analysis were valid, the calculations included in the TSD are incorrect.

Table 14 of the TSD includes the cost effectiveness analysis of the different turbine models. (TSD at pp. 34-35.) The LMS 100 is the smallest unit and therefore, like other smaller units, the capital cost per MW is somewhat higher than larger units – approximately $300 /kW for the LMS 100 compared to $230/kW for several 200MW units. However, the LMS 100 is about 13% more fuel efficient than the other units proposed by PSE. This fuel efficiency will offset the additional capital costs if the unit operates at sufficient capacity factors. For purposes of setting annual operating hours (and corresponding fuel use) Ecology assumes that the LMS 100 units may run up to 2,880 hours per year, and the proposed permit sets a fuel limit based on 2,880 hours per year. (TSD at p.5.) However, the "calculation" for incremental cost analysis is based on an assumption that the units will only run 630-657 hours per year. (TSD at p.34.) PSE cannot have it both ways. Even if the incremental cost analysis were a valid method of excluding more efficient turbines, which it is not, the calculations in the TSD unfairly bias the result against the more efficient but smaller LMS 100 turbines by assuming a capacity factor of only 7.5%, which is insufficient to allow the more expensive but more efficient turbines to recover their higher capital cost through more efficient and lower cost operation. If PSE plans to operate the new Fredonia units at only 7.5% capacity factor, then the permit's operating hours and fuel usage should reflect those estimates.[12] Instead, PSE uses one set of operating assumptions to calculate the "incremental cost" of more efficient turbines, and another set of operating assumptions to set their maximum operating limits in the permit. The calculation to support the BACT analysis must be consistent with the actual permitted conditions, and therefore any determination of adverse economic impact must be based on the permitted fuel usage/hours of operation.[13]

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[11] Attachment B, Pennsylvania Department of Environmental Protection, Sept. 6, 2011 Plan Approval Review Memo, York Plant Holdings, LLC, Plan Approval No. 67-05009C, p.13.

[12] In 2009 units 3 and 4 at Fredonia operated for 903 and 882 hours respectively. *See,* EPA Air Markets Program data www.ampd.epa.gov, visited April 13, 2013.

[13] *See, e.g.,* NSR Manual at p.B.68 (citing an example where cost effectiveness calculation considers permitted operating hours as the basis for establishing a disproportionate cost impact for SCR).

The TSD and PSE's application also do not provide any justification for the "all-in" capital expenses for the different turbine designs.[14] New plants can have a large disparity in capital costs, but many of these costs are related to site specific issues, such as the need to drive pilings for foundations, that have nothing to do with the particular turbine that is being installed. In this case, PSE does not break out the different turbine capital costs compared to other site-related costs. However, it is very unlikely that all of the capital expense differences are due only to the model of turbine selected. For example, PSE's application asserts that the difference between the LMS 100 and the GE 7FA.04 is $94 million. (TSD at p.35.) However, this $94 million is substantially **more than the actual cost of the two LMS units.** In other words, even if the GE 7FA.04 turbines were free, the difference in cost between the LMS 100 turbine and the GE 7FA.04 turbine would not be as high as the application purports. The GTW Handbook cites the cost of LMS 100 turbines at $300/kW ($60 million for two units), and a study prepared for New York City (as a purchaser) lists the cost at $35 million for one unit (or $70 million for two).[15] Ecology must reconcile how PSE's application concludes that the LMS 100 units cost $94 million **more** than the GE 7FA.04 units when the cost of the LMS 100 turbines is only $60-70 million.

Sierra Club examined three operating scenarios:[16] 2880 hours of operation; 2000 hours of operation; and 1,000 hours of operation. In each instance, the LMS100 demonstrated the lowest combined cost for recovery of the capital cost of the equipment, the fuel cost and the cost maintenance.[17] **Under these assumptions, there is no added cost to achieve the additional $CO_2$ reductions associated with the LMS 100.**

### 2. Hour of Operation for Peaking Unit(s) are Too High

Ecology based its emission calculations on hours of "standard" peaking mode operations, plus start-ups and shutdowns. (TSD at p.12.) However, the proposed permit sets maximum operating hours based on annual fuel use. (Proposed Permit §VII(A)(3) at p.12.) Setting maximum operating hours based on total fuel usage increases the total hours of operation because the calculations assume a compliance margin for hours of operation. In practice, the units will operate much more efficiently, and therefore setting a maximum fuel limit would result in even higher annual operating hours than the 2,880 and 2,280 in the proposed permit. In addition, Ecology provides no basis for the underlying operating scenario assumptions that it makes. For example, despite being the most efficient unit, the LMS 100 has the highest maximum annual fuel use. (TSD at p.12.) The Proposed Permit includes an additional 96 start-ups for a total of 240 at **each** LMS 100 unit, compared to 140 startups for the other units. (Proposed Permit at p.13; TSD at p.10.) There is no support in the TSD or in the application for the difference in operating scenarios between the LMS 100 and the other turbine designs. Nor is there any apparent basis for these assumptions. Even if PSE plans to change its dispatch depending on the unit selected, then that information – including any relevant dispatch studies – must be included in the public record. Otherwise there is no basis for, and no way for the public

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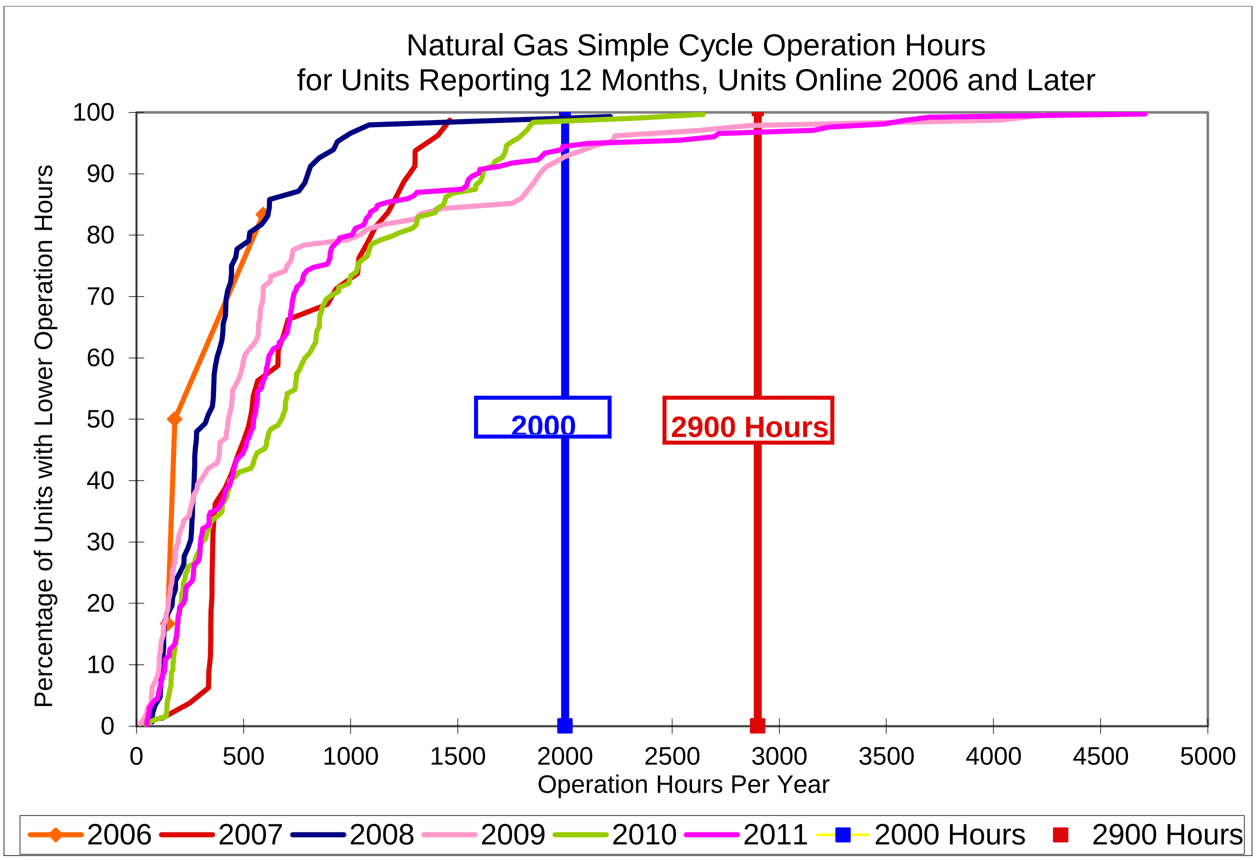
[14] TSD at p.35; Application, Appendix H at p.5-17.
[15] *Capacity Expansion Study For The Gowanus and Narrows Generating Stations*, Burns and Roe Enterprises, Inc October 19, 2006, p.13. (available at: http://www.dec.ny.gov/docs/permits_ej_operations_pdf/ncapacity.pdf )
[16] Sierra Club relied on figures that reflect the most current ratings for the units identified in the TSD, as published in the 2011-2012 *Gas Turbine World Handbook,* published by Pequot Publishing, Inc. ("GTW Handbook").
[17] Attachment A (showing Sierra Club calculations).

to evaluate, why the proposed permit assumes that some designs would be operated differently than other designs at the same proposed facility.

a) Peaking Units Operate Less than 2000 Hours Annually

The TSD states that the Fredonia project must "respond to rapidly changing and often short-term peak power demands on PSE's system." (TSD at p.31.) However, the annual operating hours for all of the proposed units are much higher than typical peaking units. The available data show that almost all simple cycle combustion turbine units have low operating hours – but they also appear to show that a few large simple cycle units have high capacity factors. The TSD assumes that the LMS 100 would operate 2,880 hours per year excluding startup and shutdown, while the remaining units would operate 2,280 hours per year. (TSD at p.5.) This equates to capacity factors of 33% and 26%, respectively. The histogram in Figure 1 shows that the annual operating hours in the proposed permit are too high. The "knee in the curve" for these data appears to be below 2000 hours for 2011 (the most favorable[18] year for industry), thus showing that operation greater than 2000 hours is not consistent with the normal operation of simple cycle units.

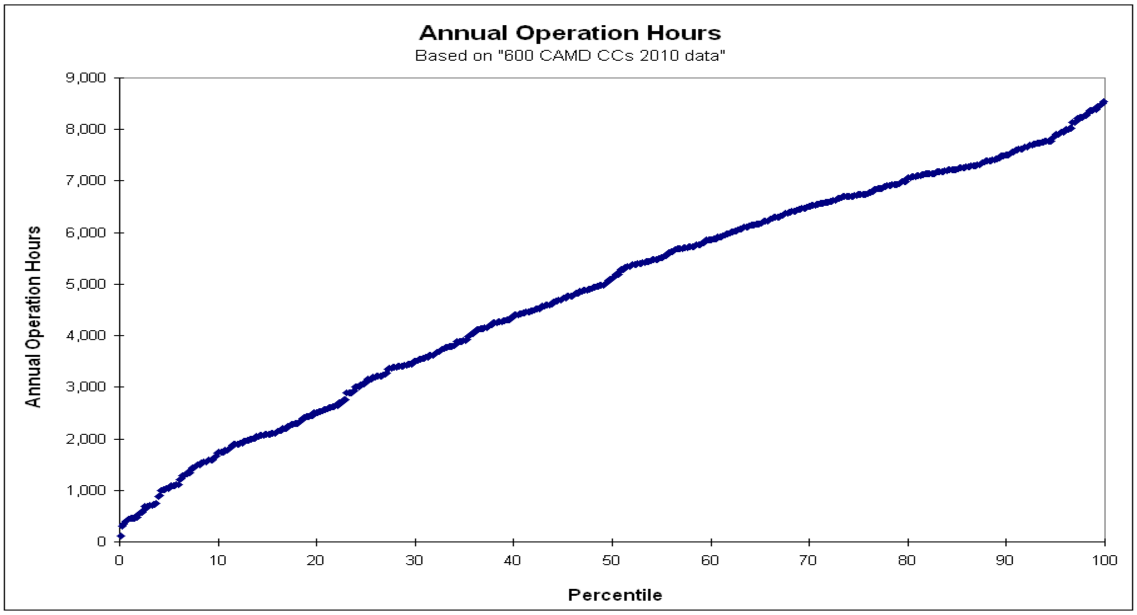
Figure 1. Hours of Operation for Combustion Turbines, by Year[19]




[18] For 2008, it is closer to 1100 hours.
[19] First year of operation 2006 or later, as determined by earliest occurrence of CAMD CEMS data. This data is included in electronic format submitted to Ecology via email as Attachment C.

We note that even 2000 hours of operation may represent simple cycle units that are in intermediate load rather than peaking operation, especially if such use is seasonal. We also note that there are a substantial number of combined cycle units that are designed for intermediate load applications but that may have limited hours of operation because of market conditions. Eighty-two of the 592 recently constructed combined cycle units in the EPA CAMD data set, Figure 2, operate less than 2000 hours per year; 143 of those units operated less than 2900 hours per year.

Figure 2. Hours of Operation for Combined Cycle Units




These data suggest that an hour of operation assumption above 2,000 hours does not sufficiently differentiate peaking from intermediate-load units. Intermediate units may operate seasonally, but for many hours at a time once started up. Such intermediate units are seasonal or load following, and these units are not true peaking units. In the proposed permit, Ecology must set the operational hours (and corresponding fuel limits) based on the characteristics of a peaking unit because it expressly rejected consideration of combined cycle units on the grounds that PSE needed the Fredonia project for "peaking applications." (TSD at p.31.) If PSE plans to operate Fredonia as an intermediate resource rather than a peaking resource, then the BACT analysis must fully consider combined cycle units as a feasible alternative.

Industry practice provides what appears to be the most useful definition of a peaking unit. Rather than the total hours per year of operation, General Electric defines "peaking" units in terms of an average hour of operation per startup. GE Performance defines base load as operation at 8,000 hours per year with 800 hours per start. It then defines peak load as operation at 1250 hours per year with five hours per start.[20] Ecology should set the maximum operating

[20] Brooks, F., GE Power Systems, *GE Gas Turbine Performance Characteristics, GER-3567H*, p.14 (available at: http://www.muellerenvironmental.com/documents/GER3567H.pdf.)

hours for the Fredonia plant based on typical peaking units operating hours of 2,000 hours per year with limits on the number of hours per start, to ensure that the proposed simple cycle turbines are used as true peaking units rather than as base load or intermediate load units.[21] If PSE plans to operate Fredonia for more than 2,000 hours per year, then such use should be considered intermediate or load following and the GHG BACT analysis must consider alternative technologies, such as combined cycle, that can operate more efficiently and therefore at lower GHG emission rates. If PSE plans to use the Fredonia plant as a true peaking facility, then the permit's limits should reflect the expected maximum operating hours of a peaking plant and the limited hours of operation per start, rather than the inflated hours of 2,880 and 2,280 hours for the proposed simple-cycle turbines.

### 3. Exclusion of CCCT's is Inappropriate

Even if the permit maximum annual fuel limits are adjusted to reflect a true peaking unit, Ecology must provide support for its conclusion that more efficient combined-cycle units are incapable of meeting the needs of a peaking facility. The data in Figure 2 above indicate that many combined cycle units operate at less than 2,000 hours per year, which suggests that those units may operate as peaking facilities.

Ecology proposed a fuel limit equivalent to 2,880 hours of full load operation for the LMS 100 units and 2,280 hours of operation of the other units. The proposed permit also has different limits for the number of starts (240/144) for these units. (TSD at p.10.) As discussed above, these operating limits exceed typical peaking applications. Nevertheless, Ecology rejected combined-cycle turbine units because "[s]imple cycle combustion turbines are best suited, and more cost-effective for peaking applications." (TSD at p.31.) Ecology further appeared to agree with PSE's conclusion that "fast start CCCT are unproven technology" that neither Siemens nor GE have "commercially constructed and operated a fast start CCCT." (TSD at pp. 31-32.) This conclusion is unsupported and factually incorrect.

Fast start CCCTs have been used in peaking applications since 1989, including, *inter alia*, the Henrietta Plant in California.[22] A consultant's report prepared for the City of Yorba Linda, CA, identifies 44 existing or planned fast start CCCTs that range in size from 5 MW to 292MW.[23] More recently, NRG Energy, Inc. signed a contract in 2010 for one of the most recent advanced designs in the size range of the Fredonia plant - a Siemens Flex Plant 10 design – at the El Segundo Plant in California.[24] The Siemens Flex Plant 10 is designed to serve the peaking power market and has qualified for the non-spinning reserve market.[25] Construction of each of two 275 MW power islands at the El Segundo Plant is expected to be complete in August,

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[21] To provide PSE with a measure of flexibility, while still distinguishing between seasonally operated intermediate-load units and peaking units, we recommend that the GE norm of 1250 hours per year be relaxed to 2000 hours per year.

[22] http://www.energy.ca.gov/2010publications/CEC-800-2010-014/CEC-800-2010-014.PDF

[23] Cole, Jerold *Anaheim Canyon Power Project: Combined Cycle versus Simple Cycle Peaking Power Plant Configuration* (2009), Docket No 07-AFC-9 (available at: http://www.energy.ca.gov/sitingcases/canyon/documents/intervenors/2009-05-26_City_of_Yorba_Linda_Comparison_of_Combined-Cycle_vs_Simple_Cycle_TN-51684.pdf).

[24] http://www.elsegundorepowering.com/

[25] http://www.energy.siemens.com/co/en/fossil-power-generation/power-plants/gas-fired-power-plants/combined-cycle-power-plant-concept/scc6-5000f-1x1-flex-plant-10.htm

2013.[26] This unit employs the same SGT6-5000F turbine that is one of the options identified by PSE. While it has a slightly larger capacity than the GE 7FA.05 (275 MW for the FlexPlant 10 compared to 215 MW for the GE unit), there is nothing in the record suggesting that this larger capacity would render the FlexPlant 10 as "infeasible" for a large electricity provider such as PSE.

Ecology's rejection of fast start CCCT technology on the basis that it would require the project to be fundamentally redefined is unsupported by the TSD and the application. As noted above, fast start CCCT's are capable of meeting peaking applications. The proposed permit assumes a very high annual maximum operating usage. As the total operating hours of the units increase, a combined cycle unit will become more cost effective. Unless the permit contains a limitation on the hours of operation that more clearly reflects the operation of a peaking unit, Ecology must fully analyze whether a fast start CCCT could economically meet the requirements of the project. Ecology cannot simply reject CCCTs as technologically infeasible in step 2 of the BACT analysis when there is evidence that combined-cycle units can meet the ramping requirements of facilities that operate more than 2000 hours per year. Ecology must include combined cycle as a feasible control option in the BACT analysis and consider its cost effectiveness in later steps of the top-down BACT analysis.

#### 4. The TSD Does not Provide Sufficient Support for the Elimination of Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is a technology that involves capture and storage of $CO_2$ emissions to prevent their release into the atmosphere. (TSD at p.29.) Ecology appropriately considered CCS from gas turbines to be a technically feasible alternative. (TSD p.30) However, Ecology rejected CCS as BACT based on its apparent agreement with PSE's technical and cost analysis of CCS. (TSD at p.31.) This conclusion is unsupported because PSE failed to conduct a thorough analysis of the technical potential and cost of CCS.

##### a) Availability of Saline Formations

PSE claims that deep saline formations are not a viable option in Washington for CCS.[27] Ecology agreed with this conclusion, finding that there was "no available saline formation within a 50 mile radius of the facility." (TSD at p.31.) There is no basis for this conclusion. The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) released the fourth edition of the United States Carbon Utilization and Storage Atlas (Atlas IV) in 2012.[28] The West Coast Regional Carbon Sequestration Partnership (WESTCARB) in Atlas IV clearly identified the Northwest, and the Puget basin in particularly, as a prime area of saline storage.

> In Oregon and Washington, western coastal basins containing sandstone and shale sequences up to 10,000 meters (33,000 feet) thick have sites that appear suitable for $CO_2$ storage. The total $CO_2$ storage resource for these sedimentary basins is in the range of 40 billion to 590 billion metric tons

[26] http://www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2010/fossil_power_generation/efp201009120.htm
[27] Application, Appendix H, p.5-10.
[28] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/

> (50 billion to 650 billion tons). The basin with the largest $CO_2$ storage potential is Washington's Puget Trough.[29]

Skagit Bay and nearby inland sites, which are less than 10 miles from the Fredonia site, are shown on the WESTCARB map as a potential saline storage area. Other suitable locations may be even closer. It is therefore incorrect to assume, without any supporting references or documentation, that saline formations are unavailable to provide for CCS.

b) Cost of CCS

CCS is by far the most effective add-on GHG control technology. PSE's application shows that the $CO_2e$ emissions rate of the LMS-100 turbine with CCS would be 120 lb/MW-hr.[30] This is an order of magnitude lower than the proposed permit's BACT limit of 1,138 lb/MW-hr for the LMS 100 without CCS. Despite its finding that CCS was by far the most effective GHG control technology, Ecology rejected CCS in step four of the top-down process on the basis of PSE's conclusion that the $CO_2$ avoided using CCS was not cost effective. (TSD at p. 31.) However, PSE's analysis assumed a cost of $76 per ton based on a published November 2010 U.S. Department of Energy cost estimate for combined cycle natural gas plants with CCS systems installed.[31] PSE then compared the $76 per ton national figure with a $20 per ton $CO_2e$ approximate social cost of carbon based on an EPA presentation.[32] This analysis is flawed for multiple reasons.

First, the PSE application concedes that PSE "has not attempted a project-specific or site-specific cost estimate for implementing one of the CCS options discussed above."[33] This generalization of CCS costs, which Ecology accepted without further analysis, is not appropriate. Ecology is required to make site-specific findings as to the cost of pollution control at the Fredonia plant, and not merely the generic costs nationally. (NSR Manual at p.B.35.)

Second, Ecology's exclusion of CCS based on cost is inappropriate because there is no evidence that CCS at Fredonia would be different from the cost of CCS or other BACT options at similar plants. When determining if a pollution control option has sufficiently adverse economic impacts to justify rejecting that option and establishing BACT based on a less effective option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." (NSR Manual at B.44.) This high standard for eliminating a feasible BACT technology exists because the collateral impacts analysis in BACT step 4 is intended only as a safety valve for when impacts unique to the facility make application of a technology inapplicable to that specific facility. Ecology and PSE inappropriately compare the cost of CCS to an arbitrary threshold. To reject CCS, BACT requires a demonstration that the costs of pollutant removal are disproportionately high for the specific facility compared to the cost of control at other facilities. (NSR Manual, p.B.45.) No such CCS comparison was made here. Ecology merely identified some examples of other BACT permits where CCS had been rejected (TSD at p.29-30) rather than comparing the relative cost of CCS between Fredonia and other comparable facilities.

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[29] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/WESTCARB-Atlas-IV-2012.pdf (page 96)
[30] Application, Appendix H, Table 5-4, p.5-13.
[31] Application, Appendix H, p.5-13.
[32] Application, Appendix H, p.5-14.
[33] Application, Appendix H, p.5-13.

Third, even if it was appropriate to compare the incremental cost of $CO_2$ control to an arbitrary threshold, which it is not, the assumption that $20 per ton of $CO_2$e avoided is an appropriate threshold is completely unsupported. There are several other sources concluding that carbon has a much higher social cost. A recent study found that social cost of carbon estimates range from $28 up to $893.[34] These thresholds suggest that CCS at $76/ton would be a more economic choice compared to higher estimated social costs of carbon.

In summary, to reject CCS based on cost-effectiveness at step 4, Ecology must determine that the cost of CCS at Fredonia is disproportionate to the cost of the same technology applied to similar sources elsewhere. Failing that, the applicant must at the very least evaluate the costs of CCS at Fredonia against the best estimate of the costs of failing to require the same level of control as would result from the use of CCS. That was not done for the draft permit; instead, Ecology evaluated the national generic cost-per-ton of CCS control on natural gas combined cycle plants, against an arbitrary $20/ton figure, failing to reference the alternative social cost of carbon or the costs of the same or similar levels of $CO_2$ capture and sequestration elsewhere. Such analysis represents clear error – and it is insufficient to justify rejection CCS as $CO_2$ BACT for Fredonia.

### 5. PM Limits are too High

The proposed permit's PM BACT limits far exceed comparable limits. Ecology states, "it is impractical to compare the proposed PM emission limits with PM emission limits and performance data from simple cycle combustion turbines in other regions." (TSD at p.20.) This conclusion is based on the assumption of generally higher sulfur content in Canadian natural gas compared to other sources of natural gas such as those in California. (TSD at p.20.) Ecology therefore relies on two BACT PM permitted limits for simple cycle turbines in Washington State. These permit limits are not the appropriate benchmark. Compliance stack tests are often orders of magnitude lower than BACT limits in the RBL Clearinghouse. Since there are numerous permitted gas turbines operating in Washington using Canadian natural gas, there should be a ready source of data to determine whether an increase in PM limits is necessary because of the properties of Canadian natural gas. Ecology should review stack tests of similar uncontrolled natural gas fired units that use Canadian natural gas to determine whether an increase in BACT limits is warranted. Such an evaluation should be made part of the record and be subject to public comment.

### 6. The Air Quality Analysis Is Insufficient

Ecology determined that the plant's CO, $PM_{10}$ and $PM_{2.5}$ impacts would not cause a violation of the NAAQS or the increments solely on the basis of a comparison between the facility's predicted impacts and "significant impact levels" or "SILs." (TSD at 46.) This conclusion is insufficient unless Ecology determines that the impacts, even if below the SIL, are not sufficient when added to background concentrations and impacts from other nearby facilities, to cause or contribute to a violation of the ambient air quality standards or the increments. For example, Ecology's analysis indicates that the 24-hour $PM_{2.5}$ impacts from the proposed new combustion turbine(s) could be 0.48 to 1.149 $\mu g/m^3$. (TSD at 46.) If the background concentration and

[34] Ackerman, *Climate Risks and Carbon Prices: Revising the Social Cost of Carbon*, p. 2 (available at: http://www.sei-international.org/mediamanager/documents/Publications/Climate-mitigation-adaptation/Economics_of_climate_policy/sei-climate-risks-carbon-prices-2011-full.pdf).

impacts from other nearby facilities are near the 35 $\mu g/m^3$ NAAQS (or 2 $\mu g/m^3$ and 9 $\mu g/m^3$ increments), then this amount of pollution could cause a violation of the standards. There is no basis in the regulations or the Clean Air Act for permitting a facility that will cause or contribute to a violation of the NAAQS or an increment simply because its' impact is "below the SIL." Therefore, absent a determination by Ecology (on the record) that the impacts from the facility will not cause or contribute to a violation of the NAAQS or increment notwithstanding the fact that they are below an arbitrary number set as the SIL, there is not a sufficient legal basis on which to issue the permit.

Notably, the only SIL that was ever actually adopted into the PSD regulations—for $PM_{2.5}$—was recently vacated by the D.C. Circuit. *See Sierra Club v. EPA*, Slip Op., Case No. 10-1413 (D.C. Cir. Jan. 22, 2013).Moreover, even if the use of a SIL without an additional determination that the plant's impacts will not cause or contribute to a violation of the NAAQS or increment notwithstanding that they are below the SIL threshold was allowed, the concept of the SIL is based on *de minimis* theory of law. Under that theory, Ecology is still required to demonstrate that the SIL is at a level below which regulating the air pollution impact would be of trivial or no value. Ecology has not made that determination on the record here.

### 7. <u>No Consideration of Secondary PM2.5 Formation</u>

It appears that the air quality analysis includes only the impacts from primary $PM_{10}$ and $PM_{2.5}$. However, as Ecology is aware, large amounts of the $PM_{2.5}$ in the ambient air are the result of secondary formation from precursors that will also be emitted from the Fredonia plant. Ecology's air quality analysis for particulates must include the impact from both primary and secondary $PM_{2.5}$.

Sierra Club appreciates the opportunity to provide these comments.

Sincerely,

*/s/ Travis Ritchie*

Travis Ritchie
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# Exhibit 5

**BEFORE THE ENVIRONMENTAL APPEALS BOARD**
**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

| | |
|---|---|
| IN RE: | ) |
| PIO PICO ENERGY CENTER, LLC | ) PSD Appeal Nos. 12-04, 12-05 & 12-06 |
| PSD Permit No. SD 11-01 | ) |

**DECLARATION OF TRAVIS RITCHIE IN SUPPORT SIERRA CLUB'S BRIEF IN RESPONSE TO SUPPLEMENTAL BRIEFS**

I, Travis Ritchie, declare:

1. I am a resident of California. I am over the age of twenty-one and have personal knowledge of the statements made herein. This declaration is filed in support of Sierra Club's Brief in Response to Supplemental Briefs.

2. I am an attorney of the Sierra Club Environmental Law Program ("Club"). As an attorney of the Club, I have been substantially involved and have personal knowledge of the docket regarding Pio Pico Energy Center LLC's application for Prevention of Significant Deterioration ("PSD") permit to construct the Pio Pico Energy Center.

3. As an attorney for the Sierra Club, I can attest that Exhibit 1 is to the best of my knowledge a true and correct copy of a February 5, 2012 *ex parte* communication noticed by Pio Pico Energy Center in California Public Utilities Commission docket A.11-05-023. This document is available from the California Public Utilities Commission's website at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M057/K738/57738621.PDF.

4. As an attorney for the Sierra Club, I can attest that Exhibit 2 is to the best of my knowledge a true and correct copy of an April 13, 2012 letter and attachments sent to Gerardo Rios, EPA Region 9, on behalf of Pio Pico Energy Center. This letter and attachments are identified as Administrative Record #I.56 in Docket No. EPA-R09-OAR-2011-0978, Pio Pico Energy Center, PSD Permit SD 11-01. This document was provided to me upon request on February 13, 2013 by Roger Kohn, USEPA Region 9 - Air Division (AIR-3), 75 Hawthorne Street, San Francisco, CA 94105-3901.

5. As an attorney for the Sierra Club, I can attest that Exhibit 3 is to the best of my knowledge a true and correct copy of excerpted pages 1 and 23-28 from Corrected Comments submitted by the Sierra Club, Environmental Defense Fund, Natural Resources Defense Council, Earthjustice, National Wildlife Federation, Environmental Law and Policy Center, Southern Environmental Law Center, and Clean Air Council on July 3, 2012 addressing the EPA's proposed rule on *Standards of Performance for Greenhouse Gas Emissions for Stationary Sources: Electricity Utility Generating Units*.

Docket No. EPA-HQ-OAR-2011-0660. This document is available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-10887

6. As an attorney for the Sierra ClubClub, I can attest that Exhibit 4 is a true and correct copy of comments submitted by Sierra Club to the Washington Department of Ecology on April 17, 2013regarding the proposed PSD permit for the Fredonia Generating Station (Washington Permit No. PSD-11-05).

I declare under penalty of perjury that the foregoing is true and correct and based on my personal knowledge.

Executed on this 29th day of April 2013.

_/s/ *Travis Ritchie*___________

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