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March 19, 2013

VIA HAND DELIVERY

Ms. Patricia Kelly, Siting Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Redondo Beach Energy Project (12-AFC-03)
Air Quality Modeling Information

Dear Ms. Kelly:

On behalf of Applicant AES Southland Development, LLC, enclosed herein for docketing in the above-referenced proceeding, please find correspondence submitted to the South Coast Air Quality Management District ("District"), dated March 15, 2013. Such correspondence was submitted to the District in response to requests for further information needed to complete the engineering evaluation of the Redondo Beach Energy Project. In addition to the enclosed correspondence, Applicant provides five (disks) containing only the HARP Input and Output Air Dispersion Modeling Files. Should you require additional disks containing this data, please do not hesitate to let me know.

Respectfully submitted,

Kristen T. Castaños

KTC:jmw
Enclosures

AES Redondo Beach
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Long Beach, CA 90803
tel 562 493 7891
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March 15, 2013

Mr. Brian Yeh
Senior Manager, Mechanical, Chemical, and Public Services Team
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4178

Subject: Redondo Beach Energy Project Permit Application (Facility ID# 115536)

Dear Mr. Yeh:

AES Southland Development, LLC (AES-SLD) is submitting this letter in response to the South Coast Air Quality Management District's (AQMD) February 8, 2012, request for additional information needed to complete the engineering evaluation of the Redondo Beach Energy Project (RBEP). The remainder of this letter presents AES-SLD's responses to the requested information.

1) Start-up Emissions

   If during start-up the process is aborted the process will count as one start-up. Does this clarification change your response?

   Response: AES-SLD understands that if a start is aborted after combustion begins fuel combustion, it will count as a start.

2) Fast Start Technology

   Please provide a step-by-step process description for the cold start-up of the combustion turbine, combustion turbine generator, heat recovery steam generator, and steam turbine generator. Also, please include a discussion of key design changes from a conventional combined cycle system.

   Response: AES-SLD is developing RBEP to provide local capacity and to assist in the integration of renewable energy in support of California's Renewable Portfolio Standard objectives. The RBEP's design accomplishes the project objectives by being able to start up quickly, increase/decrease project electrical output quickly, efficiently generate electricity over a large range of output (120 to 500 megawatts), and capable of numerous start up and shutdowns. The existing Redondo Beach Generating Station (RBGS) current operations support grid reliability and stability. In order to do so, RBGS requires a significant start up period (over 18 hours) and as a result, is required to operate overnight at minimum loads in order to be available for operation the following day, which precludes the use of renewable energy when available. The RBEP avoids this situation by being capable of starting the combustion turbines and achieving approximately 70 percent of the rated electrical output (approximately 360 megawatts) within 10 minutes of initiating a start up. Furthermore, with multiple combustion turbines, RBEP supports electrical grid reliability by being able to operate fewer, smaller units over a wider electrical output rate at a higher thermal efficiency than larger combined-cycle or simple-cycle peaking projects.

The strategy of the design that facilitates meeting RBEP's project objective includes selection of combustion turbines with specific characteristics, heat recovery steam generator (HRSG) designs/material composition, and steam turbine design. No one design feature enables RBEP to achieve fast starts.

The combustion turbine (CT) start up is initiated by mechanically turning the compressor/turbine rotor to a starting speed. Once rotor starting speed is achieved, fuel combustion is initiated and after a short stabilization period the rotor speed is accelerated to rated speed (3600 revolutions per minute). This is referred to as a full speed – no load (FSNL) condition. After FSNL is achieved, the CT electrical generator is synchronized to the phase of electrical grid and the turbine load is increased. At approximately 70 percent turbine load, the dry low nitrogen oxides (NO_X) combustors revert from the starting mode to the pre-mix mode where they are capable of achieving a 9 parts per million (ppm) NOx and 10 ppm carbon monoxide (CO) emissions.

The heat recovery steam generators (HRSGs) are specifically designed with materials and operating conditions that do not constrain the fast start and ramp of the combustion turbine (CT), yet provide sufficient steam production for enhanced overall efficiency. A steam bypass system provide an easy matching of the steam conditions to the steam turbine (ST) requirements and a de-coupling of the HRSG from the ST, further enabling the short and simplified start-up and operation of the unit. After the CT is started, the HRSGs start producing steam. When the steam is of sufficient quality and quality, steam is gradually introduced to the ST. Each HRSG is fitted with a non-return valve and steam sparge line that provides a small amount of steam to the off-service HRSG(s) within the power block. This minimizes the amount of time needed to warm the other HRSG(s) within the power block, allowing the selective catalytic reduction and carbon monoxide (CO) catalysts to reach nominal operating temperature quickly. It is expected that during staged operation (meaning at least one CT is operating) that these components will be maintained at nominal temperature reducing the time required for a start up and minimizing start up emissions.

Shutdown of the power island is fully automatic. Once a shutdown is initiated, the operating CT is unloaded; the generator breakers open automatically and the CT initiates a cool-down and coast-down cycle. Simultaneously as the CT load is reduced, HRSG steam production is reduced and eventually the steam pressure is reduced. To achieve the fast start times, an ST shutdown is desired from the highest possible pressure to ensure the HRSG remains hot or warm. After CT and ST are electrically disconnected from the grid, the turbine control systems will automatically engage a turning gear after the turbine rotors have coasted to a stop and the power block is ready to re-start at this time.

3) Health Risk Assessment

a. Please explain why the 120 ppb formaldehyde is applicable to the proposed natural gas fired turbine.

Response: AES-SLD proposed a 1 parts per million (ppm) volatile organic compound (VOC) emission limitation for the RBEP turbines/fired heat recovery steam generators. Using the published AP-42 formaldehyde emission factor of 7.1×10^{-4} pounds per million British thermal units (lb/MMBtu) equates to a formaldehyde emission concentration of approximately 300 parts per billion (ppb) or approximately one-third of the total proposed VOC emission limitation. AES-SLD believes, based on source test data, that the formaldehyde emissions will be significantly less than 300 ppb. As a result, AES-SLD believes that a lower emission factor of 2.88×10^{-4} lb/MMBtu, which equates to a formaldehyde emission concentration of approximately 120 ppb, is appropriate for the proposed natural gas fired turbine.

b. Please use the controlled emission factor of 3.6×10^{-4} lb/MMBtu formaldehyde listed in Table 3.4-1 of AP-42 (not the uncontrolled emission factor of 7.1×10^{-4} lb/MMBtu in Table 3.1-3).

Response: Revised Table 5.1B.5bR of the permit application (the "R" indicates that this is a revised table) presents the revised hazardous air pollutant emission estimates using the AQMD requested formaldehyde emission factor of 3.6×10^{-4} lb/MMBtu (equating to a formaldehyde concentration of approximately 150 ppb).

Based on the revised formaldehyde emissions presented above, the predicted RBEP operational excess cancer risk and hazard indices (HI) for each turbine are presented in revised Table AQMD-2R. The revised excess cancer risk and HI were based on using the inhalation cancer potency factor and acute/chronic reference exposure levels presented in AFC Table 5.9-2 and the maximum modeled formaldehyde impact for each turbine.

Redondo Beach Energy Project
Table 5.1B.5bR (BASIS: AP-42 EMISSION FACTORS PER SCAQMD)
Summary of Turbine Operation Emissions – Air Toxics
February 2013

Assume:

Maximum Heat Input Case:	Baseload operation with duct burners firing	
Total Operations (per turbine w/o DB -includes startup and shutdown hours)	6365	hr/yr
Total Operations (per turbine w/ DB)	470	hr/yr
Gas Heat Content	1020	MMBtu/MMSCF
Maximum Hourly Heat Input (per turbine w/o DB)	1492	MMBtu/Hr (HHV)
Maximum Hourly Heat Input (per turbine w/ DB)	1999	MMBtu/Hr (HHV)
Ave Annual Heat Input (per turbine w/o DB)	1398	MMBtu/Hr (HHV)
Ave Annual Heat Input (per turbine w/ DB)	1905	MMBtu/Hr (HHV)
Number of Turbines	3	

Proposed Project	Emission Factor		Emissions (per Turbine)			Emissions (Facility Total)		
Compound	**(Lb/MMCF)[a]**	**(Lb/MMBTU)**	**lb/hr**	**lb/yr**	**TPY**	**lb/hr**	**lb/yr**	**TPY**
Ammonia[b]	5 ppm	-	13.2	85844	42.9	39.60	257532	128.8
Acetaldehyde	0.041	4.00E-05	0.080	392	0.196	0.24	1175	0.59
Acrolein	0.0065	6.40E-06	0.013	63	0.0313	0.038	188	0.09
Benzene	0.012	1.20E-05	0.024	117	0.0587	0.072	352	0.18
1,3-Butadiene	0.00044	4.30E-07	0.00086	4.21	0.00210	0.0026	13	0.006
Ethylbenzene	0.033	3.20E-05	0.064	313	0.157	0.19	940	0.47
Formaldehyde[c]	0.367	3.60E-04	0.719	3524	1.76	2.2	10573	5.3
Hexane	NA	NA	NA	NA	NA	NA	NA	NA
Naphthalene	0.0013	1.30E-06	0.0026	12.7	0.00636	0.0078	38	0.019
PAHs[d]	0.0022	2.20E-06	0.0018	8.8	0.0044	0.005	26.4	0.01322
Propylene (propene)	NA	NA	NA	NA	NA	NA	NA	NA
Propylene Oxide	0.030	2.90E-05	0.058	284	0.142	0.17	852	0.43
Toluene	0.133	1.30E-04	0.260	1273	0.636	0.78	3818	1.9
Xylene	0.065	6.40E-05	0.128	627	0.313	0.38	1880	0.94
TOTAL HAPs				**6619**	**3.31**		**19856**	**9.9**
TOTAL TACs				**3646**	**1.82**		**10939**	**5.5**

Notes:

[a] Emission rates based on the Section 3.1 of the U.S. EPA. AP-42, Table 3.1-3 Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines. April 2000, unless otherwise noted.

[b] Based on the operating exhaust NH_3 limit of 5 ppmv @ 15% O_2 and a F-factor of 8710.

[c] Emission factor provided in SCAQMD's February 8, 2013 letter.

[d] Carcinogenic PAHs only. Naphthalene was subtracted from the total PAH emissions and considered separately in the HRA.

TABLE AQMD-2R
RBEP Health Risk Assessment Summary: Individual Units (BASIS: AP-42 Emission Factors)[a, b]

Risk	Turbine 1	Turbine 2	Turbine 3
MICR at the PMI[c] (per million)	0.73	0.67	0.66
Chronic Hazard Index at the PMI	0.0022	0.0020	0.0020
Acute Hazard Index at the PMI	0.022	0.015	0.011

[a]The results represent the predicted risk for each individual emission unit in accordance with District Rule 1401.

[b]A source with a MICR less than one in 1 million individuals is considered to be less than significant. A chronic or acute HI less than 1.0 for each source is considered to be a less-than-significant health risk.

[c]Cancer risk values are based on the Office of Environmental Health Hazard Assessment (OEHHA) Derived Methodology.

MICR = maximum individual cancer risk
PMI = point of maximum impact

The revised formaldehyde emission factors did not alter the conclusions presented in the RBEP permit application that the project would comply with applicable laws, ordinances, regulations, and standards and does not pose a public health risk to the community.

Enclosed are compact discs containing the dispersion modeling input and output files.

4) Dispersion Modeling

AQMD planning staff identified deficiencies in the dispersion modeling performed for a related project (Huntington Beach Energy Project) and requested a revised modeling analysis. If these same deficiencies are included in the dispersion modeling performed for this project, please revise the dispersion modeling to correct those deficiencies.

Response: AES-SLD received an electronic mail request on January 18, 2013, discussing the need for a revised modeling analysis for the Huntington Beach Energy Project (HBEP). Below is a summary of the electronic mail request:

1) A 5-year meteorological dataset is required for all Prevention of Significant Deterioration (PSD) projects. The AQMD will provide those files along with the ozone files in a subsequent communication.

2) Based on your dispersion modeling analysis, the HBEP will exceed the significant impact level (SIL) for the Federal 1-hour NO_2 standard. This will require a cumulative analysis of ambient impacts for NO_2. As I explained in our phone conversation, the overly conservative nature of the Federal 1-hour NO_2 project impact analysis contained in your report would cause a larger area within the project impact contour than is necessary when performing the cumulative impact analysis. It is my understanding that such an analysis has been

prepared and will be submitted to the District for our review. Therefore, I am unable to complete my modeling review of this project until the cumulative analysis report is received.

In accordance with the above request, an addendum to the air dispersion modeling protocol that will include a cumulative analysis of ambient impacts for NO_2 to demonstrate compliance with the Federal 1-hour NO_2 standard will be submitted to the SCAQMD and after approval of the protocol and receiving the necessary modeling data from the SCAQMD for nearby emission sources, a revised modeling assessment demonstrating RBEP's compliance with the Federal 1-hour NO_2 ambient air quality standard will be provided by the end of April 2013. This scheduled submittal date is dependent on the timely receipt emissions data from the SCAQMD for the nearby emission sources needed for completion of this assessment.

5) GHG BACT Emissions Rate Calculation

a. Basis of GHG Calculations

i. Please identify the loads for each of the five estimated gross heat rates for each state.

Response: Attached is revised Table AQMD-3R, which shows the percent loads for both the gas turbine and the total plant. The total plant percent load is based on the megawatts produced divided by the total megawatts capable of being produced by either the gas turbine or the power plant.[1]

ii. Footnote 2 (of Table AQMD-3) appears to state that the gross heat rates were converted to net heat rates, but it is unclear from the table whether the results are for net heat rates. Please explain whether the heat rates are for gross or net heat rates.

Response: The heat rates presented in Table AQMD-3 (and in revised Table AQMD-3R) are on a gross basis.

iii. Please explain why the table is for an ambient air temperature of 71 degrees Fahrenheit (°F). On page 3-20, Table 3-2 – Comparison of Heat Rates and GHG Performance of Recently Permitted Projects, the RBEP results were based on 63.3°F. The revised calculations should be based on the ambient temperature that results in the worst-case emissions.

Response: During the AES-SLD's turbine evaluation, the annual average ambient temperature of 71°F was selected. However, during the preliminary engineering, a lower average ambient temperature was identified (the 63°F used in the permit application). The effect of using an ambient air temperature of 71°F would tend to slightly increase the plant heat rate and slightly decrease electrical production (over the use of a 63°F temperature).

[1] The total plant percent loads were calculated using the following equation: total plant percent load = (produced megawatts/rated megawatts at 71 degrees Fahrenheit) * 100.

Table AQMD-3R RBEP Heat Rate Estimate

RBEP Expected Annual Average Operating Profile at an Ambient Air Temperature of 71 F[1]																	Expected Annual Hours
Turbine Output	**Percent**	70	80	90	100	100 + DB[2]	70	80	90	100	100 + DB[2]	60	70	80	90	100	
Plant Output	**Percent**	23.8	26.6	29.3	32.7	41.4	49.0	54.6	60.1	66.9	74.7	73.8	74.7	82.0	90.0	100.0	
Expected Operating Hours	**Hours/year**		125					1600			DB			730			2455
Gross Plant Output	**KW**	120486	134673	148614	165985	209677	248313	276763	304592	339343	378950	374146	378956	415766	456358	507033	
Estimated Gross Heat Rate, LHV	**Btu/KWH**	7730	7562	7439	7351	7740	7501	7359	7259	7191	7453	7467	7451	7348	7267	7217	
				State 1[3]					State 2					State 3			
		Average KW	155887		**Average Btu/KWH for State 1**	7564	**Average KW**	309592		**Average Btu/KWH for State 2**	7353		**Average KW**	426452		**Average Btu/KWH for State 3**	7350

1. Operating data from TFLINK 71F Part Load Curve.xls.

2. DB = Duct firing.

3. State 1 represents a 1 on 1 configuration, State 2 represents a 2 on 1 configuration, and State 3 represents a 3 on 1 configuration.

However, the effect of this slight (8°F) difference in ambient air temperature on the overall greenhouse gas (GHG) best available control technology (BACT) analysis is insignificant.

Basing the GHG BACT analysis on a worst-case air temperature would result in an artificially high BACT limit. The operational and ambient conditions that produce the highest heat rates occur at 100 percent turbine load with an ambient temperature of 106°F. This temperature is expected to occur infrequently in the project area. Therefore, basing the GHG BACT analysis on RBEP operating under these conditions would result in GHG emissions substantially higher than the projected annual GHG emissions, which are typically based on annual average operating conditions. The GHG BACT analysis included in the permit application was based on RBEP operating at an ambient air temperature that approximates the annual average temperature over the planned operating range for the facility (24 to 100 percent). AES-SLD believes the approach used in the permit application GHG BACT analysis is also consistent with the U.S. Environmental Protection Agency (EPA) suggestion in its January 25, 2013 letter to the AQMD (referenced in the AQMD's letter to AES-SLD).[2]

b. GHG Efficiency

   i. Please provide revised emission rate calculations based on the Annual Operating Profile provided in your letter in Table AQMD-1 in response to item 3b.

Response: Tables AQMD-5b-1 and AQMD-5b-2 show the results of the revised RBEP GHG efficiency, expressed as pounds of carbon dioxide (CO_2) per megawatt-hour (lb/MWh) for the permitted operating profile.[3] As shown by these tables, the additional start-ups/shutdowns and operating hours result in a slightly higher GHG efficiency (1,070 lb/MWh for the permitted operating profile and 1,082 lb/MWh for the expected operating profile from Table AQMD-5). This result shows that the 624 start-up/shutdown events are diluted by the higher number of permitted operating hours (6,370 hours for the permitted operating profile and 2,455 hours for the expected operating profile from Table AQMD-3).

[2] EPA letter dated January 25, 2013, to Mohsen Nazemi, P.E., regarding U.S. EPA Comments on the Proposed Significant Title V Revisions and Permit to Construct for the Unit 3 Repowering at the Los Angeles Department of Water and Power – Scattergood Generating Station – "The practical operating range of the combined-cycle gas turbine should be considered in the final permit decision concerning the GHG BACT limit for the combined-cycle gas turbine."

[3] The start-ups and shutdowns heat rate calculations were not included because they are the same regardless of the number of start-ups and shutdowns.

Table AQMD-5b-1 RBEP Heat Rate Estimate

RBEP Expected Annual Average Operating Profile at an Ambient Air Temperature of 71 F[1]																	Expected Annual Hours
Turbine Output	**Percent**	70	80	90	100	100 + DB[2]	70	80	90	100	100 + DB[2]	60	70	80	90	100	
Plant Output	**Percent**	23.8	26.6	29.3	32.7	41.4	49.0	54.6	60.1	66.9	74.7	73.8	74.7	82.0	90.0	100.0	
Expected Operating Hours	**Hours/year**		292					3740			DB			2338			6370
Gross Plant Output	**KW**	120486	134673	148614	165985	209677	248313	276763	304592	339343	378950	374146	378956	415766	456358	507033	
Estimated Gross Heat Rate, LHV	**Btu/KWH**	7730	7562	7439	7351	7740	7501	7359	7259	7191	7453	7467	7451	7348	7267	7217	
				State 1[3]					State 2					State 3			
		Average KW 155887		**Average Btu/KWH for State 1**		7564	**Average KW** 309592		**Average Btu/KWH for State 2**		7353			**Average KW** 426452		**Average Btu/KWH for State 3**	7350

1. Operating data from TFLINK 71F Part Load Curve.xls.

2. DB = Duct firing.

3. State 1 represents a 1 on 1 configuration, State 2 represents a 2 on 1 configuration, and State 3 represents a 3 on 1 configuration.

Table AQMD-5b-2 RBEP Calculate Annual Average CO_2 (lb/MWh)

Annual Average - Assume all hours for each State are at the average heat rate for that State

Start Up and Stop Heat Rate Calculations

624	startups / yr	
9	min / startup	
93.6	hours startup / year	
18267	Btu/ gross kWh	Effective Heat Rate during Turbine Start
624	stops / yr	
9.5	min / stop	
98.8	hours stops / year	
16520	Btu/kWh Gross	Effective Heat Rate during Turbine Stops

Plant CO2 Efficiency Calculation

7655	Btu LHV / kWh Gross	Weighted Annual Average Heat Rate with SU/SD and no Degradation.
		(292 hrs * 7564 Btu/kWh + 3740 hrs * 7353 btu/kWh + 2338 hrs * 7350 btu/kWh + 18267 btu/kWh * 93.6 hrs + 16520 btu/kWh * 98.8 hrs)/(6370 hrs + 93.6 hrs + 98.8 hrs)
8%	Assumed Plant Degradation	
8320	Btu LHV / kWh Gross	Annual Average CO2 Efficiency with SU/SD and Degradation (7655 btu/kWh / (1 - 0.08))
1070	lb CO2 /MWh Gross	Annual Average CO2 Efficiency with SU/SD and Degradation
		(8320 btu/kWh * 1000 kWh/MWh * 1.1 HHV/LHV * $1*10^{-6}$ MMBtu/Btu * 53.02 kg CO2/MMBtu-HHV * 2.205 lb/kg)

ii. Revised GHG calculations are required to be based on the number and duration of cold starts, warm starts, hot starts, and shutdowns set forth in Table AQMD-1.

Response: The type of startup (i.e., cold, warm, and hot) is in reference to the shutdown condition (temperature/pressure) of the steam cycle major equipment when initiating the startup; i.e., the heat recovery steam generator, steam turbine, and condenser. The RBEP design is specifically employed such that the steam cycle equipment does not limit the gas turbine startup under any condition. Thus, the RBEP combustion turbines can be started and achieve minimum operating loads (70 percent) within 9 minutes for a cold, warm, or hot start. Because the GHG BACT analysis included in the permit application assumed all start-ups last 9 minutes consume the same amount of fuel, revised GHG calculations are not required.

iii. Revised GHG calculations are required to be provided for three operating loads. Since the stated load range is 70% to 100% load, please include 70%, 100%, and another load in between.

Response: The GHG BACT analysis included in the permit application already assumed turbine operation at four loads, between 70 and 100 percent load (with and without duct firing), and at plant loads between 24 and 100 percent load.

c. Your calculations were based on CO_2 only. The revised calculations are required to be based on CO_2e, including the combustion emissions of CH_4 and N_2O.

Response: The environmental performance standard promulgated by the California Energy Commission, as mandated by Senate Bill 1368, is based exclusively on CO_2.[4] Furthermore, EPA's proposed Standards of Performance Standard for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Subpart TTTT) identify that only CO_2 will be regulated.[5] Therefore, we prepared the GHG BACT analysis on the same basis as the applicable regulations.

However, using the average heat input, kilowatts, and hours per state (as shown in Table AQMD-3R), AES-SLD estimates the total annual RBEP heat input of 6,077,579 MMBtu/year. Combining the annual heat input with the published CH_4 and N_2O emission factors of 0.0038 and 0.0009 kilograms/MMBtu, respectively, converts the CH_4 and N_2O emissions into CO_2-equivalent emissions of 2,181 metric tons or approximately one-half of 1 percent of the total CO_2 GHG emissions (321,565 metric tons). Therefore, incorporating the CH_4 and N_2O emissions will not alter the results of the GHG BACT analysis included in the permit application nor does it appear consistent with either promulgated state or proposed federal GHG regulations.

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[4] California Code of Regulations (CCR), Chapter 11, Article 1,§ 2902 Greenhouse Gases Emission Performance Standard (a) The greenhouse gases emission performance standard (EPS) applicable to this chapter is 1100 pounds (0.5 metric tons) of carbon dioxide (CO_2) per megawatt hour (MWh) of electricity.
[5] Section 60.5515 states "The greenhouse gas regulated by this subpart is carbon dioxide (CO_2)."

d. The emission rate was stated to be based on MWh gross. The revised calculations are required to be on MWh net.

   Response: The megawatt-hour values referenced in Table AQMD-3 were not used in calculating the RBEP GHG efficiency shown in Table AQMD-5. Table AQMD-5 uses expected operating hours and heat rates to calculate the project's GHG efficiency.

6) GHG BACT Analysis – Other Turbine Models

a. Please identify other turbine models or other potential facility configurations that may result in higher thermal efficiencies and therefore lower GHG emissions from the proposed equipment at the facility. Please consider and analyze as necessary other potential turbine models and configurations that would make the specific project more thermally efficient.

   Response: During the project definition phase, AES-SLD evaluated other turbine models to determine the best fit with the project objectives (presented in our response to 2 above). The turbines evaluated include the following classes of combustion turbines: B/D/E, F/G, H/J, and aeroderivative turbines in both combined and simple cycle configurations. The evaluation was based on compliance with SCAQMD Rule 13304, start/ramp ability, fuel pressure requirements, combustion turbine exhaust characteristics driving the steam cycle conditions, start up/shutdown reliability and emission profiles, water consumption requirements, and particulate matter emission rates. Figure 5 of the project's permit application (Appendix 5.1D – attached for your convenience) shows the projected heat rates for a General Electric LMS100 in a simple cycle configuration, a Siemens Flex-10 plant in a combined cycle configuration, and the RBEP. Measured against the project objectives of fast starting and ramping with high thermal efficiency over the entire range of electrical output, the Mitsubishi 501D selected for RBEP clearly satisfies the majority of the project objectives.

b. Please explain how the proposed turbine has been modified to use the fast start technology. Also, please explain how the determination was made that the proposed turbine is more thermally efficient than the newer turbines available today.

   Response: AES-SLD is not proposing to modify the turbine to achieve fast starts. Almost all gas turbines (industrial and aero-derivative) are capable of achieving nominal output in 10 minutes when operated in a simple cycle configuration. The steam cycle defines the duration of a start-up as explained in 5.b.ii above.

   Efficiency of a combined cycle application (design) impacts the fast start and fast ramp capability. Highly efficient steam cycles require complex HRSG and STs, which subsequently require much more limiting operating conditions due to the multiple thermal stresses—start times are longer and ramp rates are slower. The AES-SLD configuration employs a steam plant design that provides the best possible efficiency while retaining the inherent gas turbine start and ramp features. By simplifying the HRSG and ST design, the steam cycle is less thermally efficient than what could be achieved, but since the simple design allows faster start times and ramp rates, the power island as a whole becomes more efficient for the operating conditions it will be employed under.

7) Carbon Capture and Storage

a. Capture and Compression

i. Please provide cost estimates, including for development, licensing, procurement, and construction, for the following types of carbon capture systems:

1. Sorbent adsorption

2. Physical absorption

3. Chemical absorption

Response: The capture of CO_2 from industrial gas streams has occurred for decades using several processes to separate CO_2 from other gases. These processes have been used in energy production and to produce food- and chemical-grade CO_2. In the middle of the century, gas adsorption technologies were developed at refineries for hydrogen production.[6] Three capture technologies are primarily being considered for carbon capture and sequestration (CCS): pre-combustion, post-combustion, and oxy-combustion. Pre-combustion capture refers to a process in which a hydrocarbon fuel is gasified to form a synthetic mixture of hydrogen and CO. The CO is converted to CO_2, using shift reactors, and captured before combusting the hydrogen-based fuel. The post-combustion capture technologies include the three methods identified by the AQMD, namely sorbent adsorption, physical adsorption, and chemical absorption. Oxy-combustion technology uses air separators to remove the nitrogen from combustion air so that the combustion products are almost exclusively CO_2, thereby reducing the volume of exhaust gases needed to be treated by the carbon capture system. Of these technologies, the post-combustion technology is most applicable to RBEP.

A 2009 review of available CO_2 capture technologies identified 17 facilities worldwide currently in operation, including four natural gas processing facilities and a synthetic gas facility with capture levels exceeding 1 million tons of CO_2 per year (the capture level applicable to power plant emissions). The integration of these existing technologies with power plants represents a significant cost and operating issues that need to be addressed in order to facilitate cost-effective deployment of CO_2 capture technologies.[7]

[6] Report of the Interagency Task Force on Carbon Capture and Storage, United States Department of Energy, August 2010. http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf
[7] ibid

To this end, AES-SLD explored the status of CCS development and, based on the Global Carbon Capture and Storage Institute's January 2013 CCS status report,[8] determined that there are a total of 72 large-scale integrated CCS projects (LSIP) in various stages of development worldwide, with 4 in operation in the U.S., 2 in Europe, and one each in Canada and Africa. Of the other LSIPs, only 8 are at a development stage where final design or contract execution is being considered. The remaining 56 projects are in the identification, evaluation, and project definition stage. Of the 72 projects, 39 projects are power generation projects with 4 of these projects developing CCS technologies at natural gas fired power plants. A majority of the CCS work has been focused on solid fuel power generation, primarily with integrated gasifier combined cycle designs and oxy-fuel designs.

Given that CCS is being currently employed on electrical generating units regardless of fuel type, the AQMD has requested a more detailed economic evaluation of CCS technology for the RBEP. During a recent meeting with the AQMD, they indicated that AES-SLD could use indicative pricing to define the CCS costs for RBEP. After researching indicative CCS costing data, a U.S. Department of Energy (DOE) 2012 Cost and Performance report[9] shows the cost for installing and operating a CCS system on a natural gas fired combined cycle (NGCC) combustion turbine project. Therefore, these data are being used to determine the cost of applying CCS to RBEP.

The DOE report determined the cost for developing a 615 megawatt (MW) NGCC project based on two General Electric Frame 7FA turbines (or equivalent), two HRSGs, a single reheat steam turbine, a wet mechanical cooling tower, and emission controls for oxides of nitrogen and CO with CCS. Table AQMD-7a-1 presents the installation and operating costs for the above NGCC project with CCS and comparative cost for RBEP.

TABLE AQMD-7A-1
Cost for a NGCC Power Plant with and without Carbon Capture and Sequestration

Technology	Capital Cost[a] ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-year)
NGCC	1,230	3.67	6.31
NGCC with CCS[b]	3,750	10	18.4
RBEP – Base Case	<1,000	<1.00	~6.00

[a]RBEP Capital Costs calculated based on $510 million/511,000 kilowatt (kW) gross excluding land value, taxes and insurance.

[b]NGCC with CCS assumes 85 percent carbon capture.

[8] http://www.globalccsinstitute.com/publications/global-status-ccs-update-january-2013
[9] http://bv.com/docs/reports-studies/nrel-cost-report.pdf

As shown in Table AQMD-7a-1, the expected costs of deploying CCS on RBEP would be prohibitive, resulting in over 3 times the RBEP base case capital costs. Additionally, operational variable and fixed costs would increase by a factor of 10 and 3, respectively. Finally, employing CCS at RBEP would increase the overall heat rate due to the added energy required to operate the carbon capture, compression, and transportation equipment.

Based on the results of CCS data presented in Table AQMD-7a-1, an estimate of the costs for incorporating CCS on the RBEP are presented in Table AQMD-7a-2. These costs assumed that carbon capture systems are currently available, that nearby CO_2 sequestration sites are readily available, and regulatory/land use issues regarding the siting of a high-pressure CO_2 pipeline and legal issues addressing sequestration are resolved.

TABLE AQMD-7A-2
Cost Comparison for RBEP with and without Carbon Capture and Sequestration

Technology	Capital Cost[a] ($/kW)	Capital Cost (Dollars)	Variable O&M Cost[b] ($/year)	Fixed O&M[b] ($/Year)	Total Annual O&M Costs ($/Year)
RBEP	<1,000	510,000,000	3,255,070	3,066,000	6,321,070
RBEP with CCS[c]	3,520	1,916,250,000	32,550,700	9,402,400	41,953,100
Incremental Cost of CCS[d]	2520	1,641,250,000	29,295,630	6,336,400	35,632,030

[a]RBEP cost calculated at $1,000/kW.

[b]RBEP variable and fixed O&M costs are based on Table AQMD-7a-1 costs assuming 3,255,070 MWh and 511,000 kW.

[c]RBEP with CCS cost $3750/kW - $1230/kW + $1000/kW

[d]Cost of CCS is the difference between RBEP with CCS and RBEP.

It is clear that based on the DOE study, deploying CCS at RBEP does not appear to be cost effective. It should be noted that the DOE report assumes the NGCC units have a capacity factor (ratio of actual megawatts produced in a year divided by theoretical megawatts possible in a year) of 85 percent. AES-SLD assumes the expected capacity factor of RBEP will be in the range of 15 to 25 percent with approximately 350 start-ups and shutdowns. The intermittent operation of RBEP is not factored into the above cost estimate, but is expected to both reduce the efficiency of the CCS system and increase costs on a dollars per kilowatt basis.

ii. Please examine both partial and full-capture options.

Response: AES-SLD does not consider deploying CCS on RBEP to be cost effective and partial deployment would reduce any CO_2 reduction benefit without significantly reducing operational costs.

iii. Please quantify the "significant reduction of plant output due to the high energy consumption of capture and compression systems," listed as an additional cost to RBEP in Section 3.2.2.4.1 on page 3-17.

Response: Based on the DOE report, the heat rate for the NGCC plant without CCS was estimated at 6,705 British thermal units per kilowatt-hour (Btu/kWh), whereas the heat rate for the NGCC plant with CCS was estimated at 10,080 Btu/kWh.[10] This degradation in heat rate is due to the additional electrical load required to operate the CCS system, resulting in a 33 percent reduction in performance. AES-SLD believes that the CCS heat rate degradation would push RBEP's heat rate (reported as 8,416 Btu/kWh-LHV) to over 11,000 Btu/kWh-LHV.

iv. Transport

1. Please elaborate on the concerns with transporting CO_2 via a new pipeline in an urban area mentioned in Section 3.2.2.1.1 on page 3-4:

   a. Development of new rights-of-way, and

   b. Public concern about potential for leakage.

   Response: Securing a right-of-way easement on public property for the installation and operation of a high-pressure CO_2 pipeline could result in extensive delays due to resolving concerns raised by the public based on the perceived hazards associated with the pipeline. Securing sufficient private property for siting a CO_2 pipeline would be cost prohibitive within the urban Los Angeles basin.

2. There are no existing CO_2 pipelines in California and petroleum product pipelines are not suitable for re-use of CO_2 transport.

   a. Please investigate whether there are other types of available pipelines that are suitable for re-use for CO_2 transport.

   b. Please identify such pipelines that may potentially be re-used for CO_2 transport for this project.

   Response: Based on mapping from the National Pipeline Mapping System, operated by the U.S. Department of Transportation[11], it appears that there are two existing pipelines near the RBEP site. These are a natural gas and a liquid pipeline. The natural gas pipeline is the natural gas supply to the existing Redondo Beach Generating Station, which will be reused for the RBEP. The second pipeline is a liquid pipeline that appears to be a petroleum pipeline that terminates at the Exxon Mobil refinery in Torrance.

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[10] http://bv.com/docs/reports-studies/nrel-cost-report.pdf, pages 14 and 16.
[11] https://www.npms.phmsa.dot.gov/PublicViewer/index.jsp

Natural gas transmission lines typically operate at pressures between 200 and 1,500 pounds per square inch gauge (psig).[12] Petroleum product pipelines operate at similar pressures as natural gas pipelines. Transporting CO_2 via a pipeline requires the pipeline pressure to be above 2,000 psig and at very low temperatures to maintain the CO_2 in a liquid phase. Therefore, the use of either of the existing pipelines would likely not be feasible for transporting CO_2 from RBEP.

v. Storage

1. Enhanced Oil Recovery (EOR)

   a. Please investigate oil fields amenable to EOR within pipeline distance of RBEP and potential EOR projects with companies that operate them.

   b. Please estimate the storage capacity and costs, including transportation for best options.

   c. Please evaluate options.

   Response: The California Energy Commission's 2011 Studies Impacting Geologic Carbon Sequestration Potential in California[13] determined that all zones of the Torrance Oil Field, which underlies the RBEP site, were too shallow for CO_2 sequestration. As the cost of deploying CCS at RBEP is not cost effective, identification of other sequestration sites near the RBEP site appears moot.

vi. Deep Saline Aquifer

1. Please identify formations within pipeline distance of RBEP and create a detailed evaluation.

2. Please estimate the storage capacity and costs, including transportation for best options.

3. Please evaluate options.

   Response: In the California Energy Commission's 2011 Studies Impacting Geologic Carbon Sequestration Potential in California, they noted a lack of available well log and geophysical data, which precluded the mapping of regional saline aquifers. Based on mapping by DOE's National Energy Technology Laboratory's NatCarb viewer,[14] the nearest known saline aquifer sites are undergoing early phases of evaluation. These sites are located in New Mexico, Utah, and Texas, all of which would not be considered within pipeline distance of RBEP.

[12] http://www.aga.org/Kc/aboutnaturalgas/consumerinfo/Pages/NGDeliverySystem.aspx
[13] http://www.energy.ca.gov/2011publications/CEC-500-2011-044/CEC-500-2011-044.pdf
[14] http://www.natcarbviewer.com/

vii. Additional RBEP Concerns

1. Please quantify the costs of “hiring of labor to operate, maintain, and monitor the capture, compression, and transport systems,” listed as additional costs to RBEP in Section 3.2.2.4.1 on page 3-17.

2. Please elaborate on the “resolving of issues regarding project risk that would jeopardize the ability to finance construction,” listed as an additional cost to RBEP in Section 3.2.2.4.1 on page 3-17.

Response: The estimated costs presented in response to 7a above reflect labor costs for Midwestern states. In general, labor costs in California and, in particular, the Los Angeles basin are significantly higher for craft labor needed to construct, operate, and maintain a CCS system. Table AQMD-7a-3 presents the U.S. Department of Labor Bureau of Labor Statistics mean hourly and annual wages for power plant operators for Midwestern states and California. The data show that California’s labor costs for power plant operators is approximately 30 percent higher than the average for the states shown. This wage trend likely translates to other labor categories required to construct, operate, and maintain a CCS system.

TABLE AQMD-7A-3
Power Plant Operators Hourly and Annual Wages (May 2011)

Area name	Hourly mean wage	Annual mean wage*
Alabama	$27.90	$58,020
Arkansas	$28.12	$58,490
California	$38.73	$80,570
Colorado	$31.71	$65,950
Georgia	$28.73	$59,760
Illinois	$33.94	$70,590
Indiana	$29.57	$61,500
Iowa	$24.73	$51,430
Kansas	$26.32	$54,760
Michigan	$29.74	$61,860
Minnesota	$33.60	$69,890
Missouri	$30.56	$63,560
Nebraska	$32.51	$67,620
Ohio	$28.62	$59,520
Oklahoma	$25.78	$53,630
Pennsylvania	$29.07	$60,460
Average	$29.98	$62,351

*Annual wages have been calculated by multiplying the hourly mean wage by 2,080 hours; where an hourly mean wage is not published, the annual wage has been directly calculated from the reported survey data.
SOC code: Standard Occupational Classification code -- see http://www.bls.gov/soc/home.htm

The project risk referred to in Section 3.2.2.4.1 on page 3-17 relates to the ability to finance RBEP. During the financing of a project, a potential lender will conduct due diligence to determine if a project, once constructed, can comply with environmental and contractual limitations. In the case of environmental limitations, a lender would review all permits issued for the project and assess if the project design can achieve compliance with applicable limits. In the case of air quality, the lender would compare the air emission limits with equipment vendor guarantees to determine if there is a risk that the project could not comply with the emission limits. The lender may also assess the vendor qualifications to determine if the vendor has successfully designed, fabricated, and installed similar equipment. The assumption being that a guarantee by a qualified, creditable equipment vendor that has successfully performed in the past has a higher likelihood of meeting its contractual obligations. In the event a lender determines a project may not comply with a permit limitation, financing may be more difficult to obtain, if not impossible. For contractual limitation, a lender may review the project's financial performance and revenue contracts to determine if the financial performance of the project is adequate to allow repayment of the loan.

In the case of CCS, there are additional risks associated with the lack of long-term performance for carbon capture systems on NGCC projects from equipment vendors capable of providing turn-key systems, difficulty of applying carbon capture to intermittent sources like RBEP, and the lack of approved protocols necessary to demonstrate sequestration sites.

8) Please confirm that there will be no VOC and/or toxic materials emitted by the oil/water separator identified on page 2-31 of the Project Description section of the application.

Response: Attached are completed AQMD Form 400-A and a check in the amount of $5,229.18 to obtain a permit to operate for the oil/water separator.

If you require further information, please don't hesitate contacting me at 562-493-7840.

Sincerely,

SOKane

Stephen O'Kane
Manager
AES Redondo Beach, LLC
Attachments

cc: Sarah Madams/CH2M HILL
Jennifer Didlo/AES
Kristen Castanos/Stoel Rives
Jerry Salamy/CH2M HILL
Patricia Kelly/CEC

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): AES Redondo Beach, LLC

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 115536

3. Owner's Business Name (If diff

Section B - Equipment Location Address

4. Equipment Location Is: (•) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

1100 North Harbor Drive
Street Address

Redondo Beach, CA 90277
City, Zip

Stephen O'Kane — Manager
Contact Name — Title

(562) 493-7840 — Ext. — (562) 493-7737
Phone # — Ext. — Fax #

E-Mail: stephen.okane@aes.com

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

690 N. Studebaker Road
Address

Long Beach, CA 90803
City, State, Zip

Stephen O'Kane — Manager
Contact Name — Title

(562) 493-7840 — Ext. — (562) 493-7737
Phone # — Ext. — Fax #

E-Mail: stephen.okane@aes.com

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM ( ) In Title V (•) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ( ) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- (•) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- ( ) Alter tion/Modification
- ( ) Alter tion/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: ____

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy): 01/01/2016
8b. Estimated End Date of Construction (mm/dd/yyyy): 12/31/2020
8c. Estimated Start Date of Operation (mm/dd/yyyy): 06/30/2019

9. Description of Equipment or Reason for Compliance Plan (list applicable rule): Oil/Water Separator for incorporation into Title V Revision

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / pr 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-f -profit training center) (•) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (•) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? Electrica Power Generation

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (•) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (•) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: S O'Kane

18. Title of Responsible Official: Manager

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (•) Yes

20. Print Name: Stephen O'Kane

21. Date: 03/15/2015

22. Do you claim confidentiality of data? (If Yes, see instructions.) (•) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☐ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TR ING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN