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STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of:	)	Docket No. 09-AFC-02
	)	
Application For Certification	)	**STAFF'S PREHEARING CONFERENCE**
For the Almond 2 Power Plant Project	)	**STATEMENT**
	)	

On September 8, 2010, the Almond 2 Power Plant Project Application for Certification Committee (Committee) issued a Notice of Prehearing Conference and Evidentiary Hearing. In the Notice, the Committee set the date for the Prehearing Conference and Evidentiary Hearing as October 1, 2010, and ordered each party planning to participate in the Conference to serve and file a Prehearing Conference Statement and an Exhibit List. Each Statement is required to specify the topic areas the party believes are ready for evidentiary hearings and those that are not, any disputed areas and the precise nature of the dispute, witnesses and their qualifications, a summary of testimony to be offered and the time desired to present direct testimony, time desired for cross-examination, a list of exhibits, a proposed briefing schedule, and any proposed modifications to proposed Conditions of Certification.

Staff is prepared at this time to proceed to evidentiary hearings in all topic areas. On April 30, 2010, Staff issued its Staff Assessment (SA), and on July 30, 2010, Staff issued its Revised Staff Assessment (RSA), based on comments received during the public comment period and at the Staff Workshop held on May 18, 2010. Staff held an additional public workshop on September 16, 2010, to work with the applicant to revise language to several Conditions of Certification. On September 27, 2010, Staff issued a Supplement to the Revised Staff Assessment (RSA Supplement), which includes the revised language to the Conditions of Certification discussed at the September workshop and signed Declarations of Staff's witnesses. The RSA, in conjunction with the RSA Supplement, constitute Staff's written testimony in these proceedings and

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includes all of the witnesses' qualifications. Staff's testimony for each technical area is that, with the mitigation measures recommended by Staff, the proposed project will have no unmitigated significant adverse impacts and is in compliance with all laws, ordinances, regulations and standards. At this time, Staff does not anticipate filing any further supplemental testimony, but respectfully reserves the right to file such testimony at a later date if warranted. Staff does not propose any further modifications to any of the Conditions of Certification at this time.

Staff and Applicant are the only parties that have filed written testimony and are in agreement in all technical areas. Thus, at this time, Staff is not anticipating any cross-examination of witnesses from other parties. Staff is unaware of any technical areas that may be disputed by California Unions for Reliable Energy, the only intervenor in this proceeding. During the Evidentiary Hearing, Staff proposes to sponsor testimony into the record by written declaration of each witness. Although, Staff Counsel plans to move the testimony and declarations into the record as if read without the presence of witnesses, Staff's technical witnesses may be on hand to answer any questions at the request of the Committee. In addition, Rupi Gill, Permit Services Manager - Northern Region of the San Joaquin Valley Air District, will be present telephonically to sponsor and discuss the Air District's Final Determination of Compliance.

<u>Informal Hearing Procedures</u>

The Committee has noticed its intention to use informal hearing procedures. Staff has no objection to using an informal process in this proceeding. As stated above, at the request of the Committee, Staff will have available technical witnesses to answer questions from the Committee or the public.

Proposed Schedule

Staff is prepared to proceed with evidentiary hearings in all topic areas. At this time, Staff is not aware of a need for post-hearing briefs. If briefs are required, Staff proposes to file them with the Committee within two weeks after the Hearing transcripts are made available to all parties.

DATED: September 27, 2010

Respectfully submitted,

/S/ Kerry A. Willis
KERRY A. WILLIS
Senior Staff Counsel

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814 - 1-800-822-6228 - WWW.ENERGY.CA.GOV

Docket Number: 09-AFC-02 Date: September 27, 2010

Project Name: Application for Certification for the Almond 2 Power Plant Project

Energy Commission Staff's Exhibits

TENTATIVE EXHIBIT LIST

Exhibit	Brief Description	Stipulation	Offered	Admitted	Refused	CEC Use Only
300	Revised Staff Assessment for the Almond 2 Power Plant Project, July 30, 2010.					
301	Supplement to the Revised Staff Assessment for the Almond 2 Power Plant Project, September 27, 2010.					
302	Final Determination of Compliance, San Joaquin Valley Air Pollution Control District, February 22, 2010.					

CULTURAL RESOURCES

CUL-1 Prior to the start of ground disturbance (includes “preconstruction site mobilization,” “construction ground disturbance,” and “construction grading, boring, and trenching,” as defined in the General Conditions for this project) for the reinforced segment of the natural gas pipeline on the west side of the San Joaquin River (hereinafter referred to as the “Reinforcement Segment”), the project owner shall obtain the services of a Project Geoarchaeologist (PG).

The resume for the PG shall include information demonstrating to the satisfaction of the CPM that the PG’s training and background conform to the U.S. Secretary of Interior’s Professional Qualifications Standards for prehistoric archaeology, as published in Title 36, Code of Federal Regulations, part 61, and showing the completion of graduate-level coursework in geoarchaeology or Quaternary science.

The resume of the PG shall include the names and telephone numbers of contacts familiar with the work of the PG, as a professional geoarchaeologist, on referenced projects and demonstrate to the satisfaction of the CPM that the PG has the appropriate training and experience to undertake the required geoarchaeological study.

No ground disturbance related to the Reinforcement Segment shall occur prior to CPM approval of the PG, unless specifically approved by the CPM.

Verification: 1. At least 135 days prior to the start of ground disturbance related to the Reinforcement Segment, the project owner shall provide the resume of the PG to the CPM, for review and approval.

CUL-2 The PG shall conduct geoarchaeological ~~pre-construction~~ fieldwork research on the Reinforcement Segment construction right-of-way (ROW) and the San Joaquin River fluvial system landforms (floodplain, alluvial terraces, and various overbank deposits) in the immediate vicinity, using available geoarchaeological technical literature, remote imagery, site records, and observations from a field reconnaissance of the area. Review of the cultural resources data compiled during the AFC review process shall precede the field reconnaissance.

1. The results of the ~~geoarchaeological~~ pre~~-construction~~ excavation geoarchaeological research and field reconnaissance shall be submitted to the CPM in a Geoarchaeological Pre-Excavation Research Report ~~report~~ that shall also include:
    - A large scale (≥1:12,000) map portraying the Reinforcement Segment pipeline trench and surrounding landforms,
    - Descriptions of identified landforms in and immediately around the construction ROW of the Reinforcement Segment,
    - The geomorphic history of the study area,

- The hypothesized distribution of potentially sensitive subsurface conditions,
- The age, to the extent feasible, of the landforms on which the Reinforcement Segment would be located,
- The postulated distribution of Modesto Formation (Pleistocene and possible early Holocene) landforms versus post-Modesto Formation (postglacial or Holocene) landforms,
- Recommendations for the optimal location of pre-construction geoarchaeological excavations of a portion of the Reinforcement Segment pipeline trench(CUL-3)and
- A research design for these excavations, to follow the guidance below.

~~The report filed by the Project Owner on June 7, 2010 titled, Surficial Geology of the PG&E Gas Pipeline in the Vicinity of the San Joaquin River, satisfies these requirements, and As part of the Geoarchaeological Pre-Excavation Research Report, the Project owner shall also prepare a research design for the preconstruction se excavations, which to follows the guidance below:~~

The research design shall include, but is not limited to the following elements:

- Geoarchaeological preconstruction excavations shall be located along the pipeline centerline to avoid additional impacts to buried cultural resources beyond that which would occur during construction along the Reinforcement ~~Pipeline~~ Segment ROW.
- Unless otherwise specified in the approved Geoarchaeological Pre-Excavation Research Report, ~~report~~, the excavations shall consist of backhoe trenches.
- The total depth of excavations shall be to the water table, or to the anticipated depth of the proposed pipeline installation, whichever is encountered first. The number of backhoe trenches appropriate to this study shall in no case exceed 4 trenches. Excavation methods shall include:
    a. the recordation of one measured profile from each backhoe trench to include reasonably detailed written descriptions of each lithostratigraphic and pedostratigraphic unit, a measured profile drawing, and a profile photograph with a metric scale and north arrow;
    b. b. the screening through ¼-inch hardware cloth of a small (three 5-gallon buckets) sample of sediment from the major lithostratigraphic units in each profile or from two arbitrary levels in each profile;
    c. c. collection of radiocarbon or TL (thermoluminescence) samples to date and/or correlate stratigraphic units and time horizons, with

processing of these samples at the discretion of the PG, in consultation with the CPM; and

d. d. implementation of a protocol to immediately inform the project owner of any buried prehistoric archaeological deposits encountered during geoarchaeological data collection and to facilitate informing the CPM.

2. At the conclusion of ~~the excavations~~ reconnaissance ~~field work~~ and initial data review, a meeting or teleconference with the CPM, the PG, and the project owner shall be held to review the results of the Geoarchaeological Pre- Excavation Research Report.~~ of pre-construction excavations. Decisions on whether or not to radiocarbon date or otherwise date some or all of the samples shall be made at this meeting.~~

~~3. The PG shall provide a Geoarchaeological Excavation Results Report report to the project owner and the CPM that describes the results of the geoarchaeological pre-construction excavations and the subsurface geomorphology along the Reinforcement Segment Pipeline Section ROW. This report shall include:~~

~~a. presents, in graphic and written form, a master column that characterizes the stratigraphy of the subject portion of the Reinforcement Pipeline Segment ROW, including a geologic interpretation of the approximate age of the stratigraphic subdivisions reflecting shifts in depositional history and time ranges that correspond to the prehistory and history of the region;~~

~~b. the results of the study placed in the context of what is known of the area's Quaternary geomorphology and environmental history;~~

~~c. descriptions of any encountered archaeological deposits, including an assessment of the lateral and vertical extents of each such deposit, descriptions of the material culture content and the character of the sedimentary matrix for each deposit, and an assessment of the approximate age of each deposit;~~

~~d. a preliminary interpretation of the character of the prehistoric or historic land use that each encountered archaeological deposit represents;~~

~~e. an interpretation, with reference to the information gathered and developed above, of the likelihood that buried archaeological deposits are present, and, on the basis of the current understanding of the prehistory and history of the geoarchaeological study area region, what site types are most likely to be found;~~

~~f. recommendations, on the basis of the conclusions in "e" where and to what depth archaeological monitoring should be done during construction in all project construction areas of the Reinforcement Segment;~~

g. ~~an assessment of the potential necessity and the approximate cost of mitigating project impacts to any CRHR-eligible buried archaeological deposits found during the geoarchaeological study, and recommended options for project re-design to avoid any potential CRHR-eligible deposits found;~~

h. ~~appendices to the report to include completed DPR 523 forms for any archaeological deposits encountered and recorded.~~

No ground disturbance related to the Reinforcement Segment shall occur prior to CPM approval of the Geoarchaeological Pre-Excavation Research Report ~~research design~~, unless specifically approved by the CPM.

Verification: 1. At least 120 days prior to the start of ground disturbance related to the Reinforcement Segment, the project owner shall provide the AFC, data responses, all confidential cultural resources documents, maps and drawings, and the Staff Assessment to the PG.

2. At least 90 days prior to the start of ground disturbance related to the Reinforcement Segment, the project owner shall submit the Geoarchaeological Pre-Excavation Research ~~geoarchaeological letter r~~ Report ~~and research design~~ to the CPM for review and approval.

~~3. At least 45 days after the completion of the excavations, the project owner shall submit to the Geoarchaeological Excavation Results Report to the CPM for review and approval.~~

CUL-3 Geoarchaeological preconstruction excavations along the Reinforcement ~~Pipeline~~ Segment ROW shall occur under the direction of the PG. The PG may elect to obtain specialized technical services beyond the requisite radiometric dating to assist in data-gathering and data-interpreting activities.

~~The project owner shall ensure that the PG conducts the geoarchaeological excavations field study according to the CPM-approved Geoarchaeological Pre-Excavation Research Report research design and completes and submits the Geoarchaeological Excavation Results Report. geoarchaeological field study report.~~

The PG shall provide a Geoarchaeological Excavation Results Report ~~report~~ to the project owner and the CPM that describes the results of the geoarchaeological pre-construction excavations and the subsurface geomorphology along the Reinforcement Segment ~~Pipeline Section~~ ROW. This report shall include:

a. ~~presents,~~ in graphic and written form, a master column that characterizes the stratigraphy of the subject portion of the Reinforcement ~~Pipeline~~ Segment ROW, including a geologic interpretation of the approximate age of the stratigraphic subdivisions reflecting shifts in depositional history and time ranges that correspond to the prehistory and history of the region;

b. the results of the study placed in the context of what is known of the area's Quaternary geomorphology and environmental history;

c. descriptions of any encountered archaeological deposits, including an assessment of the lateral and vertical extents of each such deposit, descriptions of the material culture content and the character of the sedimentary matrix for each deposit, and an assessment of the approximate age of each deposit;

d. a preliminary interpretation of the character of the prehistoric or historic land use that each encountered archaeological deposit represents;

e. an interpretation, with reference to the information gathered and developed above, of the likelihood that buried archaeological deposits are present, and, on the basis of the current understanding of the prehistory and history of the geoarchaeological study area region, what site types are most likely to be found;

f. recommendations, on the basis of the conclusions in "e" where and to what depth archaeological monitoring should be done during construction ~~in all project construction areas~~ of the Reinforcement Segment;

g. an assessment of the potential necessity and the approximate cost of mitigating project impacts to any CRHR-eligible buried archaeological deposits found during the geoarchaeological study, and recommended options for project re-design to avoid any potential CRHR-eligible deposits found;

h. appendices to the report to include completed DPR 523 forms for any archaeological deposits encountered and recorded.

The project owner shall review the ~~geoarchaeological~~ Geoarchaeological Excavation Results Report ~~field study report~~ and evidence consideration of any project design changes recommended by the PG.

No ground disturbance related to the Reinforcement Segment shall occur prior to CPM approval of the ~~geoarchaeological~~ Geoarchaeological Excavation Results Report. ~~field study report~~.

Verification: 1. At least 90 days prior to the start of ground disturbance related to the Reinforcement Segment, the project owner ~~shall ensure that the PG initiates the approved geoarchaeological study and~~ shall notify the CPM by letter or in an e-mail that the PG has initiated the CPM-approved ~~Geoarchaeological Excavation Research Report~~ geoarchaeological study.

2. No later than 3 weeks after the geoarchaeological pre-construction excavations conclude, the project owner, the PG, and the CPM shall meet or teleconference to review the results of pre-excavations and decide on the need for radiocarbon or other dating.

3. At least ~~45~~ 20 days prior to the start of ground disturbance related to the Reinforcement Segment, the project owner shall submit the Geoarchaeological Excavation Results ~~RPG's r~~ Report to the CRS and the CPM for review and approval.

CUL-9 The project owner shall ensure that the CRS, alternate CRS, or CRMs monitor full time all ground disturbance ~~along the linear facilities routes~~ related to the Reinforcement Segment, according to the recommendations of the Geoarchaeological Excavation Result Report ~~field study~~ required in CUL-~~1~~ 2 and CUL-3, and as approved by the CPM, to ensure there are no impacts to undiscovered resources and to ensure that known resources are not impacted in an unanticipated manner.

Full-time archaeological monitoring ~~for this project~~ related to the Reinforcement Segment shall be the archaeological monitoring of the earth-removing activities in the areas specified in the previous paragraph, for as long as the activities are ongoing. Full-time archaeological monitoring related to the Reinforcement Segment shall require at least one monitor per excavation area where machines are actively disturbing native soils. If an excavation area is too large for one monitor to effectively observe the native soil disturbance, one or more additional monitors shall be retained to observe the area.

The project owner shall obtain the services of a Native American monitor to monitor ground disturbance in any areas where Native American artifacts are discovered in native soils. Contact lists of interested Native Americans and guidelines for monitoring shall be obtained from the Native American Heritage Commission. Preference in selecting a monitor shall be given to Native Americans with traditional ties to the area that shall be monitored. If efforts to obtain the services of a qualified Native American monitor are unsuccessful, the project owner shall immediately inform the CPM. After finding those efforts to be satisfactory, the CPM may either identify other potential monitors or allow ground disturbance to proceed without a Native American monitor.

The research design in the CRMMP shall govern the collection, treatment, retention/disposal, and curation of any archaeological materials encountered.

On forms provided by the CPM, CRMs shall keep a daily log of any monitoring and other cultural resources activities and any instances of noncompliance with the Conditions and/or applicable LORS. Copies of the daily monitoring logs shall be provided by the CRS to the CPM, if requested by the CPM. From these logs, the CRS shall compile a monthly monitoring summary report to be included in the MCR. If there are no monitoring activities, the summary report shall specify why monitoring has been suspended.

The CRS or alternate CRS shall report daily to the CPM on the status of the project's cultural resources-related activities, unless reducing or ending daily reporting is requested by the CRS and approved by the CPM.

In the event that the CRS believes that the current level of monitoring is not appropriate in certain locations, a letter or e-mail detailing the justification for changing the level of monitoring shall be provided to the CPM for review and approval prior to any change in the level of monitoring.

The CRS, at his or her discretion, or at the request of the CPM, may informally discuss cultural resources monitoring and mitigation activities with Energy Commission technical staff.

Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS, or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these Conditions.

Upon becoming aware of any incidents of non-compliance with the Conditions and/or applicable LORS, the CRS and/or the project owner shall notify the CPM by telephone or e-mail within 24 hours. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the Conditions. When the issue is resolved, the CRS shall write a report describing the issue, the resolution of the issue, and the effectiveness of the resolution measures. This report shall be provided in the next MCR for the review of the CPM.

Verification:

1. At least 30 days prior to the start of ground disturbance related to the Reinforcement Segment, the CPM will provide to the CRS an electronic copy of a form to be used as a daily monitoring log.

2. Monthly while monitoring is on-going, the project owner shall include in each MCR a copy of the monthly summary report of cultural resources-related monitoring prepared by the CRS and shall attach any new DPR 523A forms completed for finds treated prescriptively, as specified in the CRMMP.

3. At least 24 hours prior to implementing a proposed change in monitoring level, the project owner shall submit to the CPM, for review and approval, a letter or e-mail (or some other form of communication acceptable to the CPM) detailing the CRS's justification for changing the monitoring level.

4. Daily and as long as no cultural resources are found related to the Reinforcement Segment, the CRS shall provide a statement that "no cultural resources over 50 years of age were discovered" to the CPM as an e-mail or in some other form of communication acceptable to the CPM.

5. At least 24 hours prior to reducing or ending daily reporting, the project owner shall submit to the CPM, for review and approval, a letter or e-mail (or some other form of communication acceptable to the CPM) detailing the CRS's justification for reducing or ending daily reporting.

NOISE & VIBRATION

NOISE-4 The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the noise levels due to operation of the project alone will not exceed: an hourly average of 47 at location M1, 45 at location M2, 47 at location M3, 49 at location M4, and 47 at location M5 (as shown on **Noise and Vibration Figure 1**).

No new pure-tone components shall be caused by the project. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints.

A. If the results from the noise survey indicate that the power plant noise at the affected receptor sites exceeds the above values, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits.

B. If the results from the noise survey indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

<u>**Verification:**</u> The project owner shall conduct a 25-hour noise survey at monitoring location M3, or at a closer location acceptable to the CPM, within 30 days of the project first achieving a sustained output of 85% or greater of rated capacity. During the period of this survey, the project owner shall also conduct short-term noise measurements between the nighttime hours of 10:00 p.m. and 7:00 a.m. at monitoring locations M1, M2, M4, and M5 or at closer locations acceptable to the CPM. All surveys shall measure one-third octave band sound pressure levels to ensure that no new puretone noise components have been caused by the project. During the 25-hour survey ~~66 percent of full load operation or greater shall be maintained between midnight and 4:00 a.m. Outside of those hours~~, output shall be maintained at a level of 50% or greater. Within 15 days after completing the survey, the project owner shall submit a summary report of the survey to the CPM. Included in the survey report shall be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limit, and a schedule, subject to CPM approval, for implementing these measures. When these measures are in place, the project owner shall repeat the noise survey.

As indicated above, the measurement of power plant noise for the purposes of demonstrating compliance with this condition of certification may alternatively be made at a location, acceptable to the CPM, closer to the facility (e.g., 400 feet from the plant boundary) and this measured level then mathematically extrapolated to determine the plant noise contribution at the affected residence.

LAND USE

LAND-2 The project owner shall ensure restoration of certain agricultural lands that are disturbed during project construction. Restoration of agricultural lands disturbed during project construction shall not interfere with maintenance of PG&E's natural gas pipeline within the existing easement. Any lands that are identified by the Farmland Mapping and Monitoring Program as Important Farmland or located within agricultural preserves shall be restored such that no conversion of Important Farmland occurs. ~~to pre-project conditions~~. Methods to restore affected agricultural lands shall include stock piling of top soil for replacement when project construction is completed. Restoration shall include grading and preparation for cultivation of affected areas and topsoil replacement. ~~Restoration shall be considered complete when affected sites are graded and prepared for cultivation and top soil replacement is accomplished to match the conditions that were present prior to disturbance of affected farmlands.~~

Verification: Before the start of any project construction work on agricultural lands the project owner shall submit written documentation to the Compliance Project Manager (CPM) describing methods that will be used to restore ~~return~~ the affected lands ~~to preproject conditions~~. Within 90 days of completion of construction of the Almond 2 Power Plant and related facilities, the project owner shall provide written documentation to the Compliance Project Manager (CPM) demonstrating that all necessary work to restore disturbed agricultural lands ~~to pre-project conditions~~ has been completed. Written documentation shall include detailed descriptions of restoration methods and corresponding maps for affected areas.

HAZARDOUS MATERIALS

HAZ-2 The project owner shall revise and update the current Hazardous Materials Business Plan (HMBP), Risk Management Plan (RMP), Spill Prevention, Control, and Countermeasure Plan (SPCC Plan), and Process Safety Management Plan (PSMP) and submit the revised plans to the Stanislaus County Environmental Resources Hazardous Materials Division (SCER-HMD) for review and comment and to the CPM for review and approval.

Verification: At least sixty (60) days prior to the start of commissioning ~~construction~~ of the A2PP, the project owner shall provide a copy of a final updated HMBP, RMP, SPCC Plan, and the PSMP to the CPM for approval.

SOIL & WATER RESOURCES

SOIL&WATER-2: The project owner shall develop a site-specific DESCP that ensures protection of water quality and soil resources of the project site and all linear facilities for both the construction and operation phases of the project. This plan shall address appropriate methods and actions, both temporary and permanent, for the protection of water quality and soil resources, demonstrate no increase in offsite flooding potential, meet local requirements, and identify all monitoring and maintenance activities. Monitoring activities shall include routine measurement of the volume of accumulated sediment in the stormwater retention basin. Maintenance activities must include removal of accumulated sediment from the retention basin when an average depth of 0.5 feet of sediment has accumulated in the retention basin. The plan shall be consistent with the grading and drainage plan as required by Condition of Certification **CIVIL-1**. The DESCP shall contain the following elements. All maps shall be presented at a legible scale no less than 1" = 100'.

- ***Vicinity Map*** – A map shall be provided indicating the location of all project elements with depictions of all significant geographic features to include watercourses, washes, irrigation and drainage canals, and sensitive areas.
- ***Site Delineation*** – The site and all project elements shall be delineated showing boundary lines of all construction areas and the location of all existing and proposed structures, pipelines, roads, and drainage facilities.
- ***Watercourses and Critical Areas*** – The DESCP shall show the location of all nearby watercourses including washes, irrigation and drainage canals, and drainage ditches, and shall indicate the proximity of those features to the construction site.
- ***Drainage*** – The DESCP shall include hydrologic calculations for onsite areas and offsite areas that drain to the site; include maps showing the drainage area boundaries and sizes in acres, topography and typical overland flow directions, and show all existing, interim, and proposed drainage infrastructure and their intended direction of flow. Provide hydraulic calculations to support the selection and sizing of the drainage network, retention facilities and best management practices (BMPs). Spot elevations shall be required where relatively flat conditions exist. The spot elevations and contours shall be extended off site for a minimum distance of 100 feet in flat terrain or to the limits of the offsite drainage basins that drain toward the site.
- ***Clearing and Grading*** – The plan shall provide a delineation of all areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slopes, locations, and extent of all proposed grading as shown by contours, cross sections, cut/fill depths or other means. The locations of any disposal areas, fills, or other special features shall also be shown. Existing and proposed topography tying in proposed contours with existing

topography shall be illustrated. The DESCP shall include a statement of the quantities of material excavated at the site, whether such excavations or fill is temporary or permanent, and the amount of such material to be imported or exported or a statement explaining that there would be no clearing and/or grading conducted for each element of the project. Areas of no disturbance shall be properly identified and delineated on the plan maps.

- ***Project Schedule*** – The DESCP shall identify on the topographic site map the location of the site-specific BMPs to be employed during each phase of construction (initial grading, project element excavation and construction, and final grading/stabilization). Separate BMP implementation schedules shall be provided for each project element for each phase of construction.
- ***Best Management Practices*** – The DESCP shall show the location, timing, and maintenance schedule of all erosion- and sediment-control BMPs to be used prior to initial grading, during project element excavation and construction, during final grading/stabilization, and after construction. BMPs shall include measures designed to control dust and stabilize construction access roads and entrances. The maintenance schedule shall include post-construction maintenance of treatment-control BMPs applied to disturbed areas following construction.
- ***Erosion Control Drawings*** – The erosion control drawings and narrative shall be designed, stamped and sealed by a professional certified engineer or erosion-control specialist.

Verification: ~~No later than 90 days prior to start of construction, the project owner shall submit a copy of the DESCP to Stanislaus County for review and comment.~~ No later than 60 days before the start of construction, the project owner shall submit a copy of the DESCP to the CPM for review and approval. ~~The project owner shall promptly submit a copy of any comments from Stanislaus County regarding the DESCP to the CPM.~~ During construction, the project owner shall provide an analysis in the monthly compliance report on the effectiveness of the drainage-, erosion- and sediment-control measures and the results of monitoring and maintenance activities. Once operational, the project owner shall provide in the annual compliance report information on the results of stormwater ~~BMP~~ facilities monitoring and maintenance activities. The information required in the DESCP may be included as part of the SWPPP. ~~The operational SWPPP may be combined with the DESCP in an effort to simplify the annual compliance reporting and CPM review. A combined DESCP/SWPPP would be verified under SOIL&WATER-3.~~

AIR QUALITY

Testimony of Tao Jiang and Brewster Birdsall, P.E., QEP

SUMMARY OF CONCLUSIONS

Staff finds that with the adoption of the attached conditions of certification, the proposed Almond 2 Power Plant (A2PP) would not result in significant air quality related impacts and that the A2PP would likely conform with applicable federal, state and San Joaquin Valley Air Pollution Control District (SJVAPCD or District) air quality laws, ordinances, regulations, and standards (LORS).

Staff finds that mitigation would be provided in the form of emission reduction credits (ERCs) as required by SJVAPCD rules, to fully offset all nonattainment pollutants and their precursors at a minimum ratio of one-to-one and to reduce the potential impacts of the proposed project to less than significant.

Global climate change and greenhouse gas emissions from the project are discussed and analyzed in **AIR QUALITY APPENDIX AIR-1**. The A2PP would emit approximately 0.51 metric tonnes of carbon dioxide per megawatt hour (MTCO2/MWh). The project would not be subject to the emission limits established by SB 1368 (Perata, Chapter 598, Statutes of 2006), known as the greenhouse gas Emission Performance Standard, because A2PP is not designed or intended for base load generation [Tit. 20, Cal. Code Regs., § 2901 (b)]. Mandatory reporting of the GHG emissions would occur while the Air Resources Board develops greenhouse gas regulations and/or trading markets. The project may be subject to GHG reduction or trading requirements as the GHG regulations become more fully developed and implemented.

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants from both the construction and operation of the proposed A2PP project. The new A2PP will be constructed adjacent to the existing 48-MW Turlock Irrigation District (TID) Almond Power Plant (APP) located in Ceres, Stainslaus County, California.

Criteria air pollutants are defined as air contaminants for which the state and/or federal government has established an ambient air quality standard to protect public health. The criteria pollutants analyzed are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), inhalable particulate matter (PM10), and fine particulate matter (PM2.5). In addition, Nitrogen oxides (NOx, consisting primarily of nitric oxide (NO) and NO_2), sulfur oxides (SOx) and volatile organic compounds (VOC) are also analyzed. NOx and VOC readily react in the atmosphere as precursors to ozone. NOx and SOx readily react in the atmosphere to form particular matter. Sulfur oxides (SOx) readily react in the atmosphere to form particulate matter and are major contributors to acid rain. Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in the context of cumulative impacts (**AIR QUALITY APPENDIX AIR-1**).

In carrying out this analysis, the California Energy Commission (Energy Commission) staff evaluated the following major points:

- Whether the A2PP is likely to conform with applicable federal, state, and SJVAPCD air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- Whether the A2PP is likely to cause significant air quality impacts, including new violations of ambient air quality standards or substantial contributions to existing violations of those standards (Title 20, California Code of Regulations, section 1743); and
- Whether the mitigation measures proposed for the project are adequate to lessen the potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws, ordinances, regulations, and standards (LORS) and policies pertain to the control of criteria pollutant emissions and the mitigation of air quality impacts. Staff's analysis examines the project's compliance with these requirements, as in **Air Quality Table 1**.

AIR QUALITY Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	**Description**
Federal	**U.S. Environmental Protection Agency**
Federal Clean Air Act Amendments of 1990, Title 40 Code of Federal Regulations (CFR) Part 50	National Ambient Air Quality Standards (NAAQS).
Clean Air Act (CAA) § 160-169A and implementing regulations, Title 42 United State Code (USC) §7470-7491 40 CFR 51 & 52 (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of pollutants that occur at ambient concentrations attaining the NAAQS. A PSD permit would not be required for the proposed A2PP project because it would not exceed 100 tons per year of NO_2, CO, or PM10. The PSD program is within the jurisdiction of the U.S. EPA.
CAA §171-193, 42 USC §7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to sources of designated nonattainment pollutants. This requirement is addressed through SJVAPCD Rule 2201.
40 CFR 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines, New Source Performance Standard (NSPS). Requires the proposed simple-cycle system to achieve 25 parts per million (ppm) NOx and achieve fuel sulfur standards.
CAA §401 (Title IV), 42 USC §7651(Acid Rain Program)	Requires reductions in NOx and SO_2 emissions, implemented through the Title V program. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2540].
CAA §501 (Title V), 42 USC §7661(Federal Operating Permits Program)	Establishes comprehensive federal operating permit program for major stationary sources. Application required within one year following start of operation. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight

Applicable Law	Description
	[SJVAPCD Rule 2520].
State	**California Air Resources Board and Energy Commission**
California Health & Safety Code (H&SC) §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.
H&SC §40910-40930	Permitting of source needs to be consistent with approved clean air plan. The SJVAPCD New Source Review program is consistent with regional air quality management plans.
California Public Resources Code §25523(a); 20 CCR §1752, 2300-2309 (CEC & CARB Memorandum of Understanding)	Requires that Energy Commission decision on AFC include requirements to assure protection of environmental quality.
California Code of Regulations for Off-Road Diesel-Fueled Fleets (13 CCR §2449, et seq.)	General Requirements for In-Use Off-Road Diesel-Fueled Fleets – Requires owners and operators of in-use (existing) off-road diesel equipment and vehicles to begin reporting fleet characteristics to CARB in 2009 and meet fleet emissions targets for diesel particulate matter and NOx in 2010.
Airborne Toxic Control Measure for Idling (ATCM, 13 CCR §2485)	ATCM to Limit Diesel-Fueled Commercial Motor Vehicle Idling – Generally prohibits idling longer than five minutes for diesel-fueled commercial motor vehicles.
Local	**San Joaquin Valley Air Pollution Control District**
SJVAPCD Rule 2201 (New and Modified Stationary Sources)	Establishes the pre-construction review requirements for new, modified or relocated emission sources, in conformance with NSR to ensure that these facilities do not interfere with progress in attainment of the ambient air quality standards and that future economic growth in the San Joaquin Valley is not unnecessarily restricted. Establishes the requirement to prepare a Preliminary Determination of Compliance (PDOC) and Final Determination of Compliance (FDOC) during SJVAPCD review of an application for a power plant. This regulation establishes Best Available Control Technology (BACT) and emission offset requirements. The A2PP project net emission increase of NOx would exceed the federal major modification threshold (40 CFR 51.165). The SJVAPCD classifies the project as a Federal Major Modification for NOx, and public notification requirements are triggered (SJVAPCD2010).
SJVAPCD Rule 2520 (Federally Mandated Operating Permits)	Establishes the permit application and compliance requirements for the federal Title V federal permit program. A2PP must submit an application to modify the existing Title V permit.
SJVAPCD Rule 2540 (Acid Rain Program)	Implements the federal Title IV Acid Rain Program, which requires subject facilities to obtain emission allowances for SOx emissions and requires fuel sampling and/or continuous monitoring to determine SOx and NOx emissions.
SJVAPCD Regulation IV (Prohibitions)	Sets forth the restrictions for visible emissions, odor nuisance, various air emissions, and fuel contaminants. Regulation IV incorporates the NSPS provisions of 40 CFR 60, including standards for stationary combustion turbines (Subpart KKKK). These rules limit emissions of NOx, VOC, CO, particulate matter, and sulfur compounds.
SJVAPCD Rule 4703 (Stationary Gas Turbines)	Limits the proposed stationary gas turbine emissions of NOx to 5 ppmv over a 3-hour averaging period and CO to 25 ppmv. Provided certain demonstrations are made, the emission limits do not apply during startup, shutdown, or reduced load periods (defined as “transitional operation periods”).
SJVAPCD Regulation VIII (Fugitive PM10 Prohibition)	Requires control of fugitive PM10 emissions from various sources.

SETTING

METEOROLOGICAL CONDITIONS

The climate in California is typically dominated by the eastern Pacific high pressure system centered off the coast of California. In the summer, this system results in low inversion layers and clear skies inland and typically early morning fog by the coast. In winter, this system promotes wind and rainstorms originating in the Gulf of Alaska and striking Northern California.

The climate of the San Joaquin Valley is characterized by hot dry summers and mild winters with precipitation almost exclusively in the winter. Very little precipitation occurs during the summer months because the Pacific high pressure blocks migrating storm systems. Beginning in the fall and continuing through the winter, the storm belt and zone of strong westerly winds begins to greatly influence California. Temperature, winds, and rainfall are variable during fall and winter months, and stagnant conditions occur more frequently than during summer.

Wind speeds are generally higher in summer than in winter and are typically north-northwesterly winds. During the spring, summer, and fall, the stronger winds are caused by a combination of offshore and thermal low pressure resulting from high temperatures in the Central Valley. During the winter months, winds are more variable and are predominantly northerly. Calm conditions occur more during winter, but are relatively infrequent throughout the year. Valley fog often occurs during these calm, stagnant atmospheric conditions, when temperature inversions trap a layer of cool, moist air near the surface. The annual average rainfall at the project site is 12.2 inches and most precipitation (80%) occurs during November through March. Long-term average temperature and precipitation data from the nearest meteorological station located in Modesto, approximately 5 miles east-northeast of the project site, indicates that July is the warmest month of the year, with a normal daily maximum and minimum of 94.3°F and 59.9°F. In the winter, January is the coldest month of the year, with an average daily maximum and minimum of 53.8°F and 37.6°F (WRCC 2009).

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability is an indicator of the air turbulence and mixing. During the daylight hours of the summer when the earth is heated and air rises, there is more turbulence, more mixing, and thus less stability. During these conditions there is more air pollutant dispersion and therefore usually reduced air quality impacts near any single air pollution source. During the winter months between storms, however, very stable atmospheric conditions occur, resulting in very little mixing. Under these conditions, minimal air pollutant dispersion occurs, and consequently higher air quality impacts may result near sources. Because lower mixing heights generally occur during the winter, along with lower mean wind speeds and less vertical mixing, dispersion occurs less rapidly.

AMBIENT AIR QUALITY STANDARDS

The United States Environmental Protection Agency (U.S. EPA) and the California Air Resource Board (ARB) have both established allowable maximum ambient concentrations of criteria air pollutants. These are based upon public health impacts and are called ambient air quality standards. The California Ambient Air Quality Standards (CAAQS), established by ARB, are typically lower (more stringent) than the federally established National Ambient Air Quality Standards (NAAQS).

Ambient air quality standards are designed to protect people who are most susceptible to respiratory distress such as asthmatics, the elderly, very young children, people already weakened by other disease or illness, and people engaged in strenuous work or exercise. The ambient air quality standards are also set to protect public welfare, including protection against decreased visibility, and damage to animals, crops, vegetation, and buildings.

Current state and federal air quality standards are listed in **Air Quality Table 2**. The averaging times for the various ambient air quality standards (the duration over which all measurements taken are averaged) range from one hour to one year. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per unit volume of air, in milligrams (mg or 10^{-3} g) or micrograms (µg or 10^{-6} g) of pollutant in a cubic meter (m^3) of ambient air, drawn over the applicable averaging period.

AIR QUALITY Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.075 ppm (147 µg/m^3)[a]	0.070 ppm (137 µg/m^3)
	1 Hour	—	0.09 ppm (180 µg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual	0.053 ppm (100 µg/m^3)	0.03 ppm (57 µg/m^3)
	1 Hour	0.100 ppm [b]	0.18 ppm (339 µg/m^3)
Sulfur Dioxide (SO_2)	Annual	0.030 ppm (80 µg/m^3)	—
	24 Hour	0.14 ppm (365 µg/m^3)	0.04 ppm (105 µg/m^3)
	3 Hour	0.5 ppm (1300 µg/m^3)	—
	1 Hour	0.075 ppm [b]	0.25 ppm (655 µg/m^3)
Respirable Particulate Matter (PM10)	Annual	—	20 µg/m^3
	24 Hour	150 µg/m^3	50 µg/m^3
Fine Particulate Matter (PM2.5)	Annual	15 µg/m^3	12 µg/m^3
	24 Hour	35 µg/m^3	—
Sulfates (SO_4)	24 Hour	—	25 µg/m^3
Lead	30 Day Average	—	1.5 µg/m^3
	Calendar Quarter	1.5 µg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 µg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 µg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

[a] On January 6, 2010, the U.S. EPA proposed to reduce the federal 8-hour ozone standard to 0.06 to 0.07 ppm.
[b] The U.S. EPA and SJVAPCD are in the process of implementing the new federal 1-hour NO_2 standard, which became effective April 12, 2010, and the new SO_2 standard became effective August 23, 2010. ~~This new federal 1-hour NO_2 standard becomes effective April 12, 2010.~~ The NO_2 NAAQS is based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations. The SO_2 NAAQS is based on the 3-year average of the 99th percentile of the yearly distribution of 1-hour daily maximum concentrations. ~~Due to this regulation being promulgated after the A2PP~~

~~application filing date, and due to a corresponding lack of guidance and modeling tools for conducting impact analyses and a lack of information regarding existing background concentrations, staff has not completed an impact assessment for compliance with this standard.~~

EXISTING AMBIENT AIR QUALITY

The federal and state attainment status of criteria pollutants in the San Joaquin Valley are summarized in **Air Quality Table 3**. Violations of federal and state ambient air quality standards for ozone, particulate matter, and CO have occurred historically throughout the region. Since the early 1970s, substantial progress has been made toward controlling these pollutants. Although air quality improvements have occurred, violations of standards for particulate matter and ozone persist.

The project site is located in Ceres, Stanislaus County. The operating monitoring station closest to the proposed site with long-term records of ozone, CO, PM10 and PM2.5 is Modesto-14th Street station. NO_2 was monitored at the Modesto-14th Street station and the Turlock-S Minaret Street station. SO_2 was monitored at the Bethel Island station.

AIR QUALITY Table 3
Attainment Status of San Joaquin Valley Air Pollution Control District

Pollutants	Attainment Status	
	Federal Classification	**State Classification**
Ozone (1-hr)	No Federal Standard	**Nonattainment (Severe)**
Ozone (8-hr)	**Nonattainment (Serious)** [a]	**Nonattainment**
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Attainment [b]	**Nonattainment**
PM2.5	**Nonattainment**	**Nonattainment**

Source: SJVAPCD 2008 (http://www.valleyair.org/aqinfo/attainment.htm).
Notes:
[a] In April 2007, the SJVAPCD Governing Board proposed to re-classify the region as "extreme" nonattainment, and the U.S. EPA is reviewing the request. The January 6, 2010 proposal to change the federal 8-hour ozone standard may affect this designation.
[b] In November 2008, EPA redesignated the San Joaquin Valley to attainment for the PM10 National Ambient Air Quality Standard (NAAQS) and approved the PM10 Maintenance Plan.

Nonattainment Criteria Pollutants

Air Quality Table 4 summarizes the existing ambient monitoring data for nonattainment criteria pollutants (ozone and particulate matter) collected by ARB and SJVAPCD from monitoring stations closest to the project site. All data in this table are marked in bold to indicate that the most-stringent current standard was exceeded. Note that an exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

AIR QUALITY Table 4
Highest Measured Concentrations of Nonattainment Pollutants (ppm or µg/m^3)

Pollutant	Averaging Time	2003	2004	2005	2006	2007	2008
Ozone (ppm)	1 hour	**0.110**	**0.104**	**0.115**	**0.120**	**0.100**	**0.127**
Ozone (ppm)	8 hour	**0.091**	**0.084**	**0.094**	**0.097**	**0.081**	**0.106**
PM10 (µg/m^3)	24 hour	**70**	**80**	**93**	**96**	**83**	**111.1**
PM10 (µg/m^3)	Annual	**28.8**	**29.1**	**29.1**	**31.7**	**27**	**31.3**
PM2.5 (µg/m^3)	24 hour	**64**	**53**	**80**	**71**	**64**	**64.5**
PM2.5 (µg/m^3)	Annual	**14.5**	**13.6**	**13.9**	**14.8**	**15**	**16**

Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html). Accessed December 2009.

Notes: Monitoring Station for ozone, PM10, and PM2.5: 2003-2008: Modesto-14th Street.

Ozone

Ozone is not a direct emission from stationary or mobile sources. It is a secondary pollutant formed through complex chemical reactions between nitrogen oxides (NOx) and volatile organic compounds (VOC). Ozone formation is highest in the summer and fall when abundant sunshine and high temperatures trigger the necessary photochemical reactions, and lowest in the winter. The days with the highest ozone concentrations commonly occur between June and August, but the region's ozone management season officially runs from April through November (the second and third calendar quarters, Q2 and Q3).

Respirable Particulate Matter (PM10)

PM10 is a mixture of small solid particles and liquid droplets with the size less than or equal to 10 microns diameter. PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from turbines, and ammonia from NOx control equipment, given the right meteorological conditions, can form particulate matter in the form of nitrates (NO3), sulfates (SO4), and organic particles. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions in the atmosphere.

PM nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. The nitrate ion concentrations during the wintertime are a significant portion of the total PM10, and an even higher contributor to particulate matter of less than 2.5 microns (PM2.5). The nitrate ion is only a portion of the PM nitrate, which can be in the form of ammonium nitrate (ammonium plus nitrate ions) or sodium nitrate.

AIR QUALITY Table 5 summerizes the ambient PM10 data collected from the nearest monitoring stations and the highest PM10 concentrations in the SJVAPCD. As shown in the table, the federal 24-hour standard has never been exceeded at the stations near the project site from 2003 to 2008. However, the CAAQS 24-hour standard has been exceeded several times each year. PM10 is primarily a winter problem, but high regional PM10 levels occur at other times of the year as well. Days with high PM10 concentrations commonly occur in November and December, but the region's PM10 management season officially runs from October through March (the first and fourth calendar quarters, Q1 and Q4). Northern California wildfires in Monterey County, Santa Clara County, and the Sierra Nevada foothills during June 2008 were probably responsible for the most-recent high PM10 concentrations.

AIR QUALITY Table 5
Highest Measured PM10 Concentrations, 2003-2008 ($\mu g/m^3$)

	Max. 24-hr Avg.	Days Above CAAQS	Days Above NAAQS	Annual
Modesto-14th Street				
2003	**70**	26.3	0	**28.8**
2004	**80**	36	0	**29.1**
2005	**93**	51.4	0	**29.1**
2006	**96**	46.3	0	**31.7**
2007	**83**	37.7	0	**27**
2008	**111.1**	-	0	**31.3**
Turlock-S Minaret Street				
2003	**87**	47.9	0	**30.6**
2004	**59**	31.2	0	**30**
2005	**83**	48.8	0	**29.3**
2006	**97**	-	0	**34.7**
2007	**73**	54.9	0	**30.8**
2008	**96**	-	0	**35.2**
District-wide				
2003	**150**	167.2	0	**52.4**
2004	**217**	113	0.9	**47.9**
2005	**131**	146.3	0	**44.3**
2006	**304**	166.8	4.2	**55.4**
2007	**172.1**	145.2	1.4	**54.8**
2008	**390.3**	182.3	4.8	**59.7**

Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html), Accessed December 2009.

Fine Particulate Matter (PM2.5)

PM2.5 refers to particles and droplets with the diameter less than or equal to 2.5 microns. PM 2.5 is believed to pose the greater health risks than PM10 because it can lodge deeply into the lungs due to the small size. PM2.5 includes nitrates, sulfates, organic carbon and element carbon, which mainly result from combustions and atmospheric reactions. Almost all combustion-related particles, including those from wood smoke and cooking, are smaller than 2.5 microns. Nitrate and sulfate particles are formed through complex chemical reactions in the atmosphere. Particulate nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. The nitrate ion concentrations during the winter make up a large portion of the total PM2.5. Ammonium sulfate is also a concern because of the ready availability of ammonia in the atmosphere.

AIR QUALITY Table 6 summarizes the ambient PM2.5 data collected from the closest monitoring station. The highest PM2.5 concentrations are generally measured in the winter. The wood-smoke particles and nitrate ions during the winter make up a large contribution to the toal PM2.5 concentration.

AIR QUALITY Table 6
Highest Measured PM2.5 Concentrations, 2003-2008 (μg/m^3)

	Max. 24-hr Avg.	Days Above NAAQS	Annual (over 3 year period)
2003	**64.0**	20.9	**14.5**
2004	**53.0**	27.3	**13.6**
2005	**80.0**	26.8	**13.9**
2006	**71.0**	26.8	**14.8**
2007	**64.0**	49.1	**15.0**
2008	**64.5**[a]	39.4	**16.0**

Note: [a] Exceptional PM concentration events, such as those caused by wind storms was excluded according to U.S. EPA AirData.
Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html), Accessed December2009.
United States Environmental Protection Agency. AirData : Access to Air Pollution Data.
(http://www.epa.gov/aqspubl1/annual_summary.html). Accessed December 2009.

Attainment Criteria Pollutants

Carbon Monoxide

Carbon monoxide (CO) is a product of incomplete combustion due to the insufficiency of oxygen content. Mobile sources are the main sources of CO emissions. Ambient concentrations of CO are highly dependent on motor vehicle activity. CO is a local pollutant, with high concentrations usually found near the emission sources. The highest CO concentrations occur during rush hour traffic in the mornings and afternoons. Ambient CO concentrations attain the air quality standards due to two state-wide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phase I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to reduced CO emissions. **AIR QUALITY Table 7** shows the maximum 8-hour CO concentrations at the closest stations.

AIR QUALITY Table 7
Maximum Concentrations of Criteria Pollutants in Attainment, 2003-2008 (ppm)

Location	Pollutant (Averaging Time)	2003	2004	2005	2006	2007	2008
Modesto-14th Street	CO (1 hour)	5.3	4.6	3.7	6.9	3.7	2.8
	CO (8 hour)	3.76	2.98	2.89	3.73	3.16	1.94
	NO_2 (1 hour)	0.091	0.065	0.072	---	---	---
	NO_2 (annual)	0.017	0.015	0.014	---	---	---
Turlock-S Minaret Street	CO (1 hour)	3.4	2.9	2.8	2.6	2.7	1.9
	CO (8 hour)	2.31	1.78	2.34	2.06	1.69	1.48
	NO_2 (1 hour)	0.090	0.061	0.065	0.058	0.053	0.063
	NO_2 (annual)	0.015	0.014	0.013	0.013	0.012	0.012
Bethel Island Road	SO_2 (1 hour)	0.016	0.015	0.017	0.017	0.018	0.012
	SO_2 (24 hour)	0.008	0.006	0.006	0.007	0.005	0.004
	SO_2 (annual)	0.002	0.002	0.002	0.002	0.002	0.001

Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html), Accessed December 2009.

Nitrogen Dioxide

Nitrogen oxides (NOx) include nitric oxide (NO) and nitrogen dioxide (NO_2). Approximately 75 to 90% of the NOx emitted from combustion sources is NO, while the balance is NO_2. NO is oxidized in the atmosphere to NO_2 by oxygen and ozone. High concentrations of NO_2 usually occur during the fall when atmospheric conditions tend to trap ground-level emissions but lack significant photochemical activitiy due to less sunlight. In the summer, the converion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) generally disperse pollutants and also engage NO in reactions with VOCs to form ozone. The formation of NO_2 in the presence of ozone is according to the following reaction:

$$NO + O_3 \rightarrow NO_2 + O_2$$

Urban areas typically have high daytime ozone concentrations that drop substantially at night as the above reaction takes place, and ozone scavenges the available NO. If ozone is unavailable to oxidize the NO, less NO_2 will form because the reaction is "ozone-limited." This reaction explains why, in urban areas, ground-level ozone concentrations drop at night, while aloft and in downwind rural areas (without sources of fresh NO emissions), ozone concentrations can remain relatively high.

The current CAAQS for NO_2 became effective in early 2008, and the U.S. EPA adopted a new 1-hour standard of 0.100 ppm (188 µg/m^3) in early 2010. Although the attainment designations have not yet been established for the new, more stringent standards, the San Joaquin Valley air basin appears likely to remain attainment for NO_2. The new federal 1-hour standard became effective in April 2010, but areas will not be given attainment designations until 2012. All recent data shows that the areas near the project site would attain all current state and federal NO_2 standards (ARB 2010). For the Turlock station, current 2006 to 2008 ARB data reflects an existing 1-hour concentration of 0.0497 ppm (93.8 µg/m^3).[1] ~~The new federal 1-hour standard would become effective some time in 2010, and areas will not be given attainment designations until 2012.~~ Data from 2003 to 2008 shows that the areas near the project site attain all current state and federal NO_2 standards (ARB 2009). See **Air Quality Table 7** for maximum 1-hour and annual NO_2 concentrations at the closest monitoring stations.

Sulfur Dioxide

Sulfur dioxide is typically emitted as a result of the combustion of fuels containing sulfur. Natural gas contains very little sulfur and consequently has very low SO_2 emissions when burned. By contrast, fuels with high sulfur content, such as coal, emit very large amounts of SO_2 when burned. Sources of SO_2 emissions come from every economic sector and include a wide variety of fuels in gaseous, liquid and solid forms. The whole state is designated attainment for all state and federal SO_2 ambient air quality standards. A new federal 1-hour standard became effective in August 2010, but areas will not be given attainment designations until 2012. Current ambient data indicates that the area would be likely to attain this new standard. See **Air Quality Table 7** for maximum 1-hour, 24-hour, and annual SO_2 concentrations at the closest monitoring station.

Summary of Existing Ambient Air Quality

In summary, staff recommends using the background ambient air concentrations in **AIR QUALITY Table 8** as the baseline for the modeling and impacts analysis. The highest criteria pollutant concentrations from the last three years of available data collected at the monitoring stations close to the project site are used to determine the recommended

[1] The 2006 to 2008 1-hour NO_2 federal design value is preliminary, provided by the California Air Resources Board. This may not reflect data that are complete or representative under U.S. EPA rules, nor do they reflect the higher concentrations that might be expected with the new near-roadway NO_2 monitoring requirements. As a result, the values are subject to change.

background values. Concentrations in excess of their ambient air quality standard are shown in bold.

The pollutant modeling analysis was limited to the pollutants listed in **AIR QUALITY Table 8**. Therefore recommended background concentrations were not determined for the other criteria pollutants (ozone and lead).

AIR QUALITY Table 8
Staff-Recommeded Background Concentrations (μg/m^3)

Pollutant	Averaging Time	Background	Limiting Standard	Percent of Standard
PM10	24 hour	**111.1**	50	**222**
	Annual	**31.7**	20	**159**
PM2.5	24 hour	**71.0**	35	**203**
	Annual	**16.0**	12	**133**
CO	1 hour	7,935	23,000	35
	8 hour	4,144	10,000	41
NO_2	1 hour	118.7	339	35
	1 hour Federal	93.8	188	50
	Annual	24.7	57	43
SO_2	1 hour	47.2	655	7
	1 hour Federal	47.2	196	24
	24 hour	18.4	105	18
	Annual	5.3	80	7

Source: AFC Table 5.1-26 (TID2009a), updated with ARB 2009.
Note that an exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

Existing Emissions

The proposed project would be located in Ceres, Stanislaus County, California, on a 4.6-acre parcel located adjacent to the existing Turlock Irrigation District (TID) Almond Power Plant (APP). The equipment at the existing TID Almond Power Plant consists of one 48 MW General Electric (GE) LM-6000 natural gas-fired, steam-injected combustion turbine generator (permitted heat input capacity of 459 million British thermal units per hour [MMBtu/hr]), and one 240 HP Cummins diesel fire pump engine.

TID would be a common owner and operator of the existing APP and the proposed A2PP, therefore some existing facilities would be shared between the two plants as follows.

Shared Existing Facilities:

- The anhydrous ammonia system, including the 12,000-gallon storage tank and unloading facilities
- The fire protection system, including the fire water storage tank and diesel-fired emergency fire pump
- The well water for service water ~~and emergency shower / eyewash stations~~
- The water treatment system

- The process water supply and wastewater discharge system
- The instrument and service air systems
- The oil/water separator
- The demineralized and reverse osmosis water storage tanks
- The administration building, including the control room and office space

Air Quality Table 9 summarizes the allowable (permitted) emissions for the existing Almond Power Plant and the actual emissions including 2007 and the first nine months of 2008.

AIR QUALITY Table 9
Existing TID Almond Power Plant, Allowable Emissions and Actual Emissions (tons/yr)

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Existing Allowable Emissions	**26.0**	**5.3**	**8.8**	**68.3**	**5.7**
Existing APP, 2007	6.4	1.1	1.9	0.8	0.3
Existing APP, 2008 (partial year)	5.6	0.9	1.5	1.3	0.2

Source: AFC Table 5.1-13 (TID2009a) and Responses to DR2 (CH2M2009f).

PROJECT DESCRIPTION AND PROPOSED EMISSIONS

The proposed A2PP would include the following new stationary sources of emissions (AFC Section 2.1.2, TID2009a and TID2009x):

- Three LM6000PG SPRINT natural-gas fired combustion turbine generators (CTG) with a nominal capacity of 54.2 MW and a heat input capacity of up to 554.9 MMBtu/hr for each gas turbine, in a simple-cycle configuration; and
- an administration building, including the control room, office space, expanded maintenance shop and warehouse, and communication systems shared by the A2PP and existing Almond Power Plant.

Separate emissions estimates for the proposed project during the construction phase, initial commissioning, and operation are each described next.

Proposed Construction Emissions

Construction of the A2PP is expected to take about 12 months. Onsite construction activities include site preparation, foundation work, installation of major equipment, and construction/installation of major structures. During the construction period, air emissions would be generated from the exhaust of off-road/non-road construction equipment and on-road vehicles and fugitive dust from activity on unpaved surfaces and material handling. Construction activities would typically occur between 7 a.m. and 3:30 p.m., Monday through Saturday (AFC Section 2.1.14, TID2009a). Additional hours may be necessary to make up schedule deficiencies, or to complete critical construction activities such as pouring concrete at night during hot weather, working around time-critical shutdowns and constraints. During some of the construction period and during the initial commissioning phase of the project, some activities would continue 24 hours per day, 7 days per week. The project would also include a new switchyard, an 11.6 mile long natural gas pipeline, a 1.8 mile gas pipeline reinforcement, and new and re-rated ~~reconductored~~ transmission lines (AFC Appendix 5.1 E-2, TID2009a, Data Responses, Set 1D, CH2M2009k). These linear facilities would be constructed prior to or simultaneously with the construction of the project.

Fugitive dust emissions would result from (AFC Appendix 5.1E-1, TID2009a):

- Dust entrained during site preparation and grading/excavation at the construction site;
- Dust entrained during on-site travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of soil at areas disturbed during construction activities.

Combustion-related emissions would be the result of:

- Exhaust from the diesel construction equipment used for site preparation, grading, excavation, trenching, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from portable welding machines;
- Exhaust from pickup trucks and diesel trucks used to transport workers and materials around the construction site;
- Exhaust from diesel trucks used to deliver concrete, fuel and construction supplies to the construction site; and
- Exhaust from automobiles used by workers to commute to the construction site.

Estimates for the highest daily emissions and total annual emissions over the 12-month construction period are shown in **Air Quality Table 10**.

AIR QUALITY Table 10
A2PP, Estimated Maximum Construction Emissions

Construction Activity	NOx	VOC	PM10	PM2.5	CO	SOx
On-site Construction Equipment (lb/day)	60.4	6.5	3.9	3.9	95.8	0.5
On-site Fugitive Dust (lb/day)		---	11.4	4.7	---	---
Off-site (On-road) Worker Travel, Truck Deliveries, Dust (lb/day)	46.0	5.2	1.2	1.2	32.7	<0.1
Off-site Linear Facility and Pipeline Equipment, Fugitive Dust, Worker Travel and Truck Delivery (lb/day)	68.7	7.5	11.0	3.6	48.0	0.1
Maximum Daily Construction Emissions (lb/day)	**175.1**	**19.2**	**27.5**	**13.4**	**176.5**	**0.6**
On-site Construction Equipment (tpy)	6.9	0.7	0.4	0.4	10.3	0.05
On-site Fugitive Dust (tpy)	---	---	1.1	0.4	---	---
Off-site (On-road) Worker Travel & Truck Deliveries (tpy)	3.4	0.4	0.1	0.1	2.9	0.01
Off-site Linear Facility and Pipeline Equipment and Fugitive Dust, Worker Travel and Truck Delivery (tpy)	2.9	0.3	0.5	0.1	2.0	0
Peak Annual Construction Emissions (tpy)	**13.2**	**1.4**	**2.1**	**1.0**	**15.2**	**0.06**

Source: AFC Appendix 5.1E Tables 5.1E-1 to 5.1E-5, Attachment 5.1E-1 (TID2009a, CH2M2009f, and CH2M2009k). Worst-case totals assume simultaneous maximum emissions during linear facility construction.

Note: Different activities have maximum emissions at different time during the construction period; therefore, total maximum daily, monthly, and annual emissions might be different from the summation of emissions from individual activities.

Proposed Initial Commissioning Emissions

New electrical generation facilities must go through initial commissioning phases before becoming commercially available to generate electricity. During this period, initial firing causes greater emissions than those that occur during normal operations because of the need to tune the combustor, conduct numerous startups and shutdowns, operate under low loads, and conduct testing before emission control systems are functioning or fine-tuned for optimum performance.

The applicant expects that approximately 288 hours of operation (AFC Table 5.1B-7a) would be needed to accomplish the various following commissioning activities for all three CTGs:

- Full Speed No Load Tests (FSNL) – a test of the gas turbine ignition system, a test to ensure that the CTG is synchronized with its electric generator, and a test of the CTG's speed control system.
- Minimum Load Tests (without SCR Operational) – several days of tuning the CTG combustor to minimize emissions and perform other checks.
- Multiple Load Tests (SCR/Oxidation Catalyst Operational at Various Levels) – several days of installing control systems and tuning to achieve NOx and CO control at design levels.

Air Quality Table 11 presents the applicant's anticipated maximum hourly and daily short-term emissions of criteria pollutants. Maximum hourly and daily emissions for NOx and CO would occur with the gas turbine in the steam blow phase and partial load tests before emission control systems are installed and operational. Emission rates for VOC, PM10, PM2.5, and SOx during initial commissioning are not expected to be higher than normal operating emissions. This is because PM10 and SOx emissions are proportional to fuel use. The total initial commissioning emissions are presented in **Air Quality Table 11.**

AIR QUALITY Table 11
A2PP, Maximum Initial Commissioning Emissions (hourly and daily)

Commissioning Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Each CTG (lb/hr)	40.40	8.41	2.5	40.0	1.56
Each CTG (lb/day)	969.6	201.8	60.0	704.6	37.4

Source: AFC Appendix 5.1B Table 5.1B-7a (TID2009a) and FDOC (SJVAPCD 2010).

Operation Emission Controls

NOx Controls

The combustion turbine would use state-of-the-art single annular combustors, with water injection and Selective Catalytic Reduction (SCR) system for NOx control. Exhaust from each turbine would enter the SCR system before being released into the atmosphere. SCR refers to a process that chemically reduces NOx to nitrogen (N_2) and water vapor (H_2O) by injecting ammonia (NH_3) into the flue gas stream in the presence of a catalyst and excess oxygen. The process is termed selective because the ammonia preferentially reacts with NOx rather than oxygen. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or noble metals are also used. Regardless of the type of catalyst used, efficient conversion of NOx to nitrogen and water vapor requires the uniform mixing of ammonia into the exhaust gas stream and a catalyst surface large enough to ensure sufficient time for the reaction to take place.

VOC and CO Controls

Emissions of CO and unburned hydrocarbons, including VOC, will be controlled with an oxidation catalyst installed in conjunction with the SCR catalyst. An oxidation catalyst system chemically reacts with organic compounds and CO with excess oxygen to form carbon dioxide (CO_2) and water. Unlike the SCR system for reducing NOx, an oxidation catalyst does not require any additional chemicals.

PM10/PM2.5 and SOx Controls

The exclusive use of pipeline-quality natural gas, a clean-burning fuel that contains very little sulfur or noncombustible solid residue, will limit the formation of SOx and particulate matter. Natural gas does contain small amounts of a sulfur-based scenting compound known as mercaptan, which results in some SOx emissions when burned. However, in comparison with other fossil fuels used in thermal power plants, SOx emissions from natural gas are very low. Particulate matter emissions from natural gas combustion are also very low compared with other fossil fuels. The sulfur content of pipeline-quality natural gas is normally less than 1 grain of sulfur per 100 cubic feet at standard temperature and pressure (gr/100 scf). High-efficiency air inlet filtration and a lube oil vent coalesce would also be used to control particulate emissions.

Proposed Operation Emissions

Air Quality Table 12 through **Air Quality Table 14** summarize the maximum (worst-case) criteria pollutant emissions associated with A2PP's normal and routine operation. Emissions for the combustion turbine system are based upon:

- NOx emissions controlled to 2.5 parts per million by volume, dry basis (ppmvd) corrected to 15% oxygen, averaged over any 1-hour period;
- VOC emissions controlled to 2.0 ppmvd with the use of good combustion practises;
- CO emissions controlled to 4.0 ppmvd at 15% oxygen for any 3-hour period;
- PM10/PM2.5 emissions at 2.5 lb/hr;
- SOx emissions based on an emission factor of 0.0028 lb per MMBtu of heat input and hourly or daily levels of fuel sulfur content of up to 1 gr/100 scf; and
- CTG firing up to 8,030 hours annually including 365 hours in startup mode (for the worst-case NOx, VOC, and CO estimates) with the option of operating up to 8,760 hours annually in steady-state mode (for the worst-case PM10/PM2.5 and SOx estimates).

Air Quality Table 12 lists the maximum hourly emissions from each CTG estimated by the applicant. Emissions for NOx, CO, and VOC during startup and shutdown events would have higher emissions than during normal operation. Since PM10 and SOx emissions are proportional to fuel use, PM10 and SOx have higher emissions rates during full-load operation.

AIR QUALITY Table 12
A2PP, Maximum Hourly Emissions Rates (pounds per hour [lb/hr])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Each CTG, steady state, full load	5.0	1.4	2.5	4.9	1.56
Each CTG, startups/shutdowns	25.0	2.0	2.5	40.0	1.56
Total, A2PP, Three CTGs	**75.0**	**6.0**	**7.5**	**120.0**	**4.7**

Source: AFC Table 5.1-18, Appendix A Table 5.1A-5 (TID2009a).

Air Quality Table 13 lists the worst-case emissions during any given day of operation of the proposed A2PP. Daily combustion turbine emissions for NOx, VOC, and CO are based on 2 hours in a startup/shutdown mode and 22 hours of full load operation, and for PM10 and SOx daily emissions are based on 24 hours of operation.

AIR QUALITY Table 13
A2PP, Maximum Daily Emissions (pounds per day [lb/day])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Each CTG, steady state, full load	110.5	30.8	55.0	107.7	34.3
Each CTG, startups/shutdowns	50.0	4.0	5.0	80.0	3.1
Total, A2PP, Three CTGs	**481.6**	**104.5**	**180.0**	**563.0**	**112.4**

Source: AFC Table 5.1-18, Appendix A Table 5.1A-5 (TID2009a).

Air Quality Table 14 lists maximum potential annual emissions from the proposed project, based on applicant and District calculations reviewed by staff. The operating assumptions include CTG firing up to 8,395 hours annually including 365 hours in startup mode (for the worst-case NOx, VOC, and CO estimates) with the option of operating up to 8,760 hours annually in steady-state mode (for the worst-case PM10 and SOx estimates).

AIR QUALITY Table 14
A2PP, Maximum Annual Emissions (tons per year [tpy])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Each CTG, steady state, full load	19.0	5.3	10.5	18.5	6.2
Each CTG, startups/shutdowns	4.6	0.4	0.5	7.3	0.3
Total, A2PP, Three CTGs	**70.7**	**17.0**	**32.9**	**77.5**	**19.4**

Source: AFC Table 5.1-18, Appendix A Table 5.1A-5 (TID2009a).

Ammonia Emissions

Ammonia (NH_3) is injected into the flue gas stream as part of the SCR system that controls NOx emissions. In the presence of the catalyst, the ammonia and NOx react to form harmless elemental nitrogen and water vapor. However, not all of the ammonia reacts with the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered from the stacks. These ammonia emissions are known as ammonia slip.

The applicant proposes to limit ammonia slip emissions from ~~the~~ this simple-cycle combustion turbine system to 10 ppmvd. However, Energy Commission staff notes that levels less than 5 ppmvd can generally be achieved by combined-cycle gas turbine power plants, during steady operations with a sufficiently designed catalyst and ammonia injection system ~~the control system can be operated and maintained to routinely achieve less than 5 ppmvd for ammonia slip~~, as established in the Guidance for Power Plant Siting (ARB 1999).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff characterizes air quality impacts as follows: All project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, PM10, PM2.5, SOx, and NH_3) are considered significant and must be mitigated. For short-term construction activities that essentially cease before operation of the power plant, our assessment is qualitative and mitigation consists of controlling construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, the mitigation includes both the Best Available Control Technology (BACT) and emission reduction credits (ERC) or other valid emission reductions to offset emissions of both nonattainment criteria pollutants and their precursors.

The ambient air quality standards used by staff as the basis for characterizing project impacts are health-based standards established by the ARB and U.S. EPA. They are set at levels that contain a margin of safety to adequately protect the health of all people, including those most sensitive to adverse air quality impacts such as the elderly, persons with existing illnesses, children, and infants.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Ambient air quality impacts occur when project emissions cause the ambient concentration of a pollutant to increase. Project-related emissions are the actual mass of emitted pollutants, which are diluted in the atmosphere before reaching the ground. Analysis begins with quantifying the emissions, then uses an atmospheric dispersion model to determine the probable change in ground-level concentrations.

Dispersion models complete the complex, repeated calculations that consider emissions in the context of various ambient meteorological conditions, local terrain, and nearby structures that affect air flow. For the A2PP, the surface meteorological data used as an input to the dispersion model included four years (2000-2004, excluding 2002) of hourly wind speeds and directions measured at the Modesto meteorological station, combined with upper-air meteorological data from Oakland International Airport monitoring station.

The applicant conducted the air dispersion modeling based on guidance presented in the *Guideline on Air Quality Models* (EPA, 2005) and the American Meteorological Society/Environmental Protection Agency Regulatory Model known as AERMOD (version 07026) for an analysis of the operating-phase emissions. The U.S. EPA designates AERMOD as a “preferred” model for refined modeling in all types of terrain. For determining NO_2 impacts of short-term emissions (1-hour averaging period), NOx emissions are further modeled using the more-rigorous Plume Volume Molar Ratio

Method (PVMRM) or the Ozone Limiting Method (OLM). Because project NOx emissions would be approximately 90% NO that could oxidize into NO_2 with sufficient time, sunlight, and availability of organic compounds or ozone, use of the PVMRM or OLM is appropriate. On October 23, 2009, the U.S. EPA released an update of the AERMOD model (version 09292), which includes the corrections to the OLM source group (OLMGROUP) feature of the OLM method. Energy Commission staff independently conducted new air dispersion modeling for NO_2 using the updated OLM method. Concurrent hourly ozone data from Modesto monitoring station is used in modeling the reactive NOx and NO_2 impacts. Staff's modeling analysis indicates higher short-term NO_2 impacts than estimated by the applicant. All results shown for 1-hour NO_2 reflects the *maximum* concentration for any one year. These results are not comparable to the new standard ~~being~~ promulgated in 2010 by U.S. EPA, which is expressed as a 3-year average of the 98th percentile value of the daily maximum 1-hour NO_2 concentrations. This federal standard became effective after the A2PP application filing date. Because ~~U.S. EPA does not yet offer modeling~~ the software and methodologies for demonstrating ~~capable of generating concentration statistics in a form that can be used in a~~ compliance with ~~demonstration for~~ this new federal standard are evolving, staff shows only ~~includes~~ the ~~California~~ maximum 1-hour NO_2 ~~standard~~ results in this analysis; conducting a more-refined analysis would show lower concentrations.

Project-related modeled concentrations for all pollutants are added to highest monitored background concentrations to arrive at the total impact of the project. The total impact is then compared with the ambient air quality standards for each pollutant to determine whether the project's emissions would either cause a new violation of the ambient air quality standards or contribute to an existing violation.

Construction Impacts and Mitigation

This section discusses the project's short-term direct construction ambient air quality impacts assessed by the applicant and, as necessary, independently assessed by Energy Commission staff. The ambient air quality impacts are modeled using AERMOD, and the impacts for NO_2 are modeled using the ozone limiting method (OLM). Construction modeling for A2PP used four years of meteorological data (2000-2004 from Modesto, excluding 2002) prepared by SJVAPCD, with concurrent ozone data also from Modesto for modeling reactive NOx and NO_2.

Air Quality Table 15 summarizes the results of the modeling analysis for construction activities. The total impact is the sum of the existing background condition plus the maximum impact predicted by the modeling analysis for project activity. The values in **bold** in the Impact and Background columns represent the values that either equal or exceed the relevant ambient air quality standard.

AIR QUALITY Table 15
A2PP, Construction-Phase Maximum Impacts (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
PM10	24 hour	17.2	**111.1**	**128.3**	50	**257**
	Annual	2.1	**31.7**	**33.8**	20	**169**
PM2.5	24 hour	9.7	**71**	**80.7**	35	**231**
	Annual	1.1	**16.0**	**17.1**	12	**143**
CO	1 hour	1,345	7,935	9,280	23,000	40
	8 hour	233	4,144	4,377	10,000	44
NO_2 [a]	1 hour-[a]	156.2	118.7	274.9	339	81
	Annual-[a]	9.4	24.7	34.1	57	60
SO_2	1 hour	7.3	47.2	54.5	655	8
	24 hour	0.6	18.4	19	105	18
	Annual	0.1	5.3	5.4	80	7

Source: AFC Appendix 5.1E Table 5.1E-7 (TID2009a), with independent staff assessment for NO_2, December 2009.
Note: a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output, and the ambient ratio method (ARM) is applied for annual NO_2, using national default 0.75 ratio.

The maximum modeled project construction impacts are predicted to occur near the northern fence lines for the worst 1-hour impacts and at the western fence line for the 24-hour impacts. For each pollutant, the concentrations would decrease rapidly with distance. The nearest residential receptors are approximately 0.3 miles from the plant, not near the fence line. Areas in the immediate vicinity of the work could experience maximum concentrations over the newly-established federal 1-hour NO_2 ambient air quality standard only if the statistical form of the standard is ignored; application of multi-year averaging of the NO_2 ~~impacts and backgrounds~~ concentrations, as specified by the new federal 1-hour NO_2 standard would reveal lower concentrations than shown here. The A2PP construction phase impacts would occur over a proposed schedule lasting about 12 months. Because the new federal one-hour NO_2 standard requires averaging the concentrations over three years, the NO_2 impacts during the single year of construction would not be likely to cause a new violation of the federal one-hour NO_2 standard. Construction impacts would be zero during the second and third years of a compliance assessment with the new federal one-hour NO_2 and SO_2 standards.

Staff believes that particulate matter emissions from construction would cause a significant impact because they will contribute to existing violations of PM10 and PM2.5 ambient air quality standards, and additionally that those emissions can and should be mitigated to a level of insignificance. Significant secondary impacts would also occur for PM10, PM2.5, and ozone because construction-phase emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would also contribute to existing violations of these standards. The direct impacts of NO_2, in conjunction with worst-case background conditions, would not create a new violation of the California 1-hour or annual NO_2 ambient air quality standard. The direct impacts of CO and SO_2 would not be significant because construction of the project would neither cause nor contribute to a violation of these standards. Mitigation for construction emissions of PM10, PM2.5, SOx, NOx, and VOC would be appropriate for reducing PM10, PM2.5, NO_2, and ozone impacts.

Construction Mitigation

The applicant proposes to reduce construction-related emissions of particulate matter, particulate matter precursors, and ozone precursors by implementing measures consistent with local air district recommendations, soil erosion control requirements, and nuisance prohibitions (AFC Section 5.1.3.8, TID2009a). Emissions mitigation and/or control techniques proposed by the applicant for reducing engine emissions during construction of A2PP include:

- Operational measures, such as limiting time spent with the engine idling by shutting down equipment when not in use;
- Regular preventive maintenance to prevent emission increases due to engine problems;
- Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and
- Use of low-emitting gasoline and diesel engines meeting state and federal emissions standards for construction equipment, including, but not limited to, catalytic converter systems and diesel particulate filter systems.

The applicant-proposed control strategies for fugitive dust emissions during construction of A2PP include:

- Use either water application or chemical dust suppressant application to control dust emissions from onsite unpaved road travel and unpaved parking areas;
- Use vacuum sweeping and/or water flushing of paved road surfaces to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials or require all trucks to maintain at least two feet of freeboard;
- Limit traffic speeds on all unpaved site areas to 15 mph;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Install tire cleaning stations or rumble plates to clean tires of all trucks exiting construction site; and
- Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant.

Staff agrees that the applicant’s proposed mitigation would be effective, although staff believes that additional construction mitigation measures could reduce potential impacts even more.

Additional measures recommended by staff would reduce construction-phase impacts to a less than significant level by further reducing construction emissions of particulate matter and combustion contaminants. Staff believes that the short-term and variable nature of construction activities warrants a qualitative approach to mitigation. Construction emissions and the effectiveness of mitigation varies widely depending on variable levels of activity, the specific work taking place, the specific equipment, soil conditions, weather conditions, and other factors, making precise quantification difficult. Despite this variability, there are a number of feasible control measures that can be implemented to significantly reduce construction emissions. Staff has determined that the use of oxidizing soot filters is a viable emissions control technology for all heavy diesel-powered construction equipment that does not use an ARB-certified low emission diesel engine. In addition, staff proposes that, prior to beginning construction, the applicant should provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies mitigation measures to limit air quality impacts during construction. Staff includes proposed staff Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement these requirements. These conditions are consistent with both the applicant's proposed mitigation and the conditions of certification adopted in similar prior licensing cases. Compliance with these conditions would substantially eliminate the potential for significant air quality impacts during construction of the A2PP project.

Operation Impacts and Mitigation

The following section discusses ambient air quality impacts that were estimated by TID and subsequently evaluated by Energy Commission staff. The applicant performed a number of direct impact modeling analyses, including both fumigation modeling and modeling for impacts during commissioning.

Routine Operation Impacts

A refined dispersion modeling analysis was performed by the applicant to identify off-site criteria pollutant impacts that would occur from routine operational emissions throughout the life of the project. A revised modeling was conducted by Energy Commission staff by using the updated OLM method. The worst case 1-hour NO_2 and CO impacts reflect startup impacts, and all other impacts reflect the impacts during normal operation. The modeled impacts are extremely conservative, since the maximum impacts are evaluated under a combination of highest allowable emission rates and the most extreme meteorological conditions, which are unlikely to occur simultaneously. Emissions rates are shown in **Air Quality Table 12** to **Air Quality Table 14**. The predicted maximum concentrations of non-reactive pollutants are summarized in **Air Quality Table 16**. PM10 and PM2.5 values are shown in bold because they exceed ambient air quality standards due to high background levels.

AIR QUALITY Table 16
A2PP, Routine Operation Maximum Impacts (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
PM10	24 hour	1.2	**111.1**	**112.3**	50	**225**
	Annual	0.1	**31.7**	**31.8**	20	**159**
PM2.5	24 hour	1.2	**71**	**72.2**	35	**206**
	Annual	0.1	**16.0**	**16.1**	12	**134**
CO	1 hour	65.9	7,935	8,000.9	23,000	35
	8 hour	6.4	4,144	4,150.4	10,000	42
NO_2 [a]	1 hour[a]	41.2	118.7	159.9	339	47
	1 hour Federal	41.2	93.8	135.0	188	72
	Annual	0.3	24.7	25.0	57	44
SO_2	1 hour	1.8	47.2	49.0	655	7
	1 hour Federal	1.8	47.2	49.0	196	25
	24 hour	0.5	18.4	18.9	105	18
	Annual	0.1	5.3	5.4	80	7

Source: AFC Table 5.1-26 (TID2009a), with independent staff assessment for NO_2, December 2009.
Note: a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output.

The maximum 24-hour PM10 impact occurs in the undeveloped area about 0.1 miles southeast of the project site, and impacts would be substantially lower at the closest single-family residences, which are located approximately 0.3 mile to the northeast. Staff believes that particulate matter emissions from routine operation would cause a significant impact because they will contribute to existing violations of PM10 and PM2.5 ambient air quality standards. Significant secondary impacts would also occur for PM10, PM2.5, and ozone because operational emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would also contribute to existing violations of these standards. The direct impacts of NO_2, in conjunction with worst-case background conditions, would not create a new violation of the NO_2 ambient air quality standards; application of multi-year averaging of the NO_2 ~~impacts and backgrounds~~ concentrations, as specified by the new federal 1-hour NO_2 standard would reveal lower concentrations than shown here. The direct impacts of CO and SO_2 would not be significant because routine operation of the project would neither cause nor contribute to a violation of these standards. Mitigation for emissions of PM10, PM2.5, SOx, NOx, and VOC would be appropriate for reducing PM10, PM2.5, and ozone impacts.

Secondary Pollutant Impacts

The project's gaseous emissions of NOx, SOx, VOC, and ammonia are precursor pollutants that can contribute to the formation of secondary pollutants, ozone, PM10, and PM2.5. Gas-to-particulate conversion in ambient air involves complex chemical and physical processes that depend on many factors, including local humidity, pollutant travel time, and the presence of other compounds. Currently, there are no agency-recommended models or procedures for estimating ozone or particulate nitrate or sulfate formation from a single project or source. However, because of the known relationships of NOx and VOC to ozone and of NOx, SOx, and ammonia emissions to secondary PM10 and PM2.5 formation, unmitigated emissions of these pollutants would likely contribute to higher ozone and PM10/PM2.5 levels in the region. Significant impacts of ozone and PM10/PM2.5 precursors would be mitigated with SJVAPCD offsets (**AQ-SC7**).

Ammonia (NH_3) is a particulate precursor but not a criteria pollutant. Reactive with sulfur and nitrogen compounds, ammonia is especially abundant in the San Joaquin Valley from natural sources, agricultural sources, and as a byproduct of tailpipe controls on motor vehicles. Ammonia particulate forms more readily with sulfates than with nitrates, and particulate formation in the San Joaquin Valley has been found to be limited by the availability of SOx and NOx in ambient air, rather than the availability of ammonia (SJVAPCD 2008 PM2.5 Plan). Offsetting SOx and NOx emissions would both avoid significant secondary PM10/PM2.5 impacts and reduce secondary pollutant impacts to a less than significant level.

Energy Commission staff recommends limiting ammonia slip emissions to the extent feasible. ~~This level of control is appropriate for avoiding unnecessary ammonia emissions, consistent with staff policy to reduce emissions of all nonattainment pollutant precursors to the lowest feasible levels.~~ Ammonia emissions are not restricted by the SJVAPCD except for avoiding excessive health risks. Energy Commission staff considered recommending offsets in sufficient quantities to eliminate any potential particulate matter formation due to NH_3 emissions, but rejected this approach because of the unclear, complex, and localized relationship of NH_3 reacting with other precursors. In lieu of offsetting this precursor, staff recommends avoiding unnecessary ammonia emissions, consistent with staff policy to reduce emissions of all nonattainment pollutant precursors to the lowest feasible levels. The feasibility of reducing ammonia slip depends on the power plant technology, the design of the NOx control system, the expected operating profile, and the cost-effectiveness. Ammonia slip levels of less than 5 ppmvd are generally most difficult to achieve by simple-cycle power plants (because of extreme temperature variations), power plants anticipating frequent startup and shutdown cycles, and late in the operational life of the catalyst. The applicant provided information on the cost of reducing ammonia slip to be compliant with a hypothetical permit limit of 5 ppmvd. TID indicated that additional catalyst material and labor would add up to $1.1 million every three to five years or doubling the catalyst change rate from AFC Table 5.14-2 (TID Comments, June 7, 2010). While staff have not confirmed this estimate, these costs would be excessive in this case. Based on the information gathered during review of this case and consistent with most other simple-cycle power plants reviewed by the Energy Commission, staff recommends that this project be required to achieve 10 ppmvd ammonia slip, which is reflected in the air district conditions (**AQ-26**). ~~Levels lower than 10.0 ppmvd can be achieved on a routine basis with a sufficiently designed catalyst and ammonia injection system. Somewhat higher costs of installing sufficient catalyst material would be offset through lower costs of purchasing ammonia that would be wastefully emitted at higher slip levels. Staff reviewed previous cases to determine an NH_3 emission reduction strategy that represents an achievable, feasible, and best available level of ammonia control for the CTGs proposed for A2PP. Supported by the recent Energy Commission decision on the Orange Grove Energy Project (08-AFC-4, Final Commission Decision, April 2009), which would use similar CTGs controlled to 5 ppmvd NH_3, and consistent with the previously mentioned ARB guidance on ammonia slip, staff recommends a condition of certification establishing catalyst improvements if ammonia slip persistently exceeds 5 ppmvd (**AQ-SC9**).~~

Fumigation Impacts

There is the potential that higher short-term concentrations of pollutants may occur during fumigation conditions. Fumigation conditions are generally short-term in nature and only compared to 1-hour standards. The applicant analyzed the air quality impacts for normal emissions under fumigation conditions using the SCREEN3 Model (AFC Table 5.1-24, TID2009a). For comparison, the same operating scenario identified in the operational impact analysis is considered for fumigation. The short-term project impacts during fumigation would not exceed the impacts for routine operation shown in **Air Quality Table 16** above. Therefore, no additional mitigation is required for fumigation impacts.

Commissioning-Phase Impacts

Commissioning impacts would occur over short-terms within the 28 days expected to be needed to complete the commissioning period. As such, commissioning impacts are compared with standards having hourly or other short-term averaging times, and standards with annual or multi-year averaging are not applicable. The commissioning emissions estimates are based on partial load operations before the emission control systems become operational, as in **Air Quality Table 11**. Impacts due to PM10, PM2.5, and SO_2 during commissioning would occur under similar exhaust conditions as those for startup while in routine operation because these emissions are proportional to fuel use. **Air Quality Table 17** shows that the commissioning-phase impacts of CO and NO_2 would be somewhat higher than those during routine operations. Commissioning-phase impacts to particulate matter and ozone concentrations would be addressed with the mitigation identified above for routine operations.

AIR QUALITY Table 17
A2PP, Commissioning-Phase Maximum Impacts (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
CO	1 hour	65.9	7,935	8,001	23,000	35
	8 hour	21.7	4,144	4,166	10,000	42
NO_2 [a]	1 hour [a]	66.6	118.7	185.25	339	55

Source: AFC Table 5.1-27 (TID2009a and SJVAPCD2010), with independent staff assessment for NO_2, December 2009.
Note: a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output.

Visibility Impacts

A visibility analysis of the project's gaseous emissions would not be required because the TID A2PP project would not qualify as a new major stationary source under the federal Prevention of Significant Deterioration (PSD) permitting program. For projects subject to PSD review by the U.S. EPA, a visibility analysis would address the nearest federally-protected Class I area. The nearest Class I areas are as follows (AFC Appendix 5.1B, TID2009a):

- Yosemite National Park 98 kilometers (km)
- Emigrant Wilderness 104 km
- Pinnacles Wilderness 117 km
- Mokelumne Wilderness 123 km
- Desolation Wilderness 154 km
- Point Reyes National Seashore 165 km

Due to its distance from Class I areas being approximately 100 kilometers, and due to the potential emissions of the project being less than the PSD applicability thresholds, Energy Commission staff anticipates that the project's impacts to visibility in Class I areas would be insignificant.

Mitigation for Routine Operation

Applicant's Proposed Mitigation

The A2PP includes a combination of BACT and emission reduction credits to mitigate air quality impacts. The equipment description, equipment operation, and emission control devices are provided in **Air Quality Project Description**.

Emission Controls

A2PP proposes two catalyst systems: the SCR and water injection system to reduce NOx; and the oxidation catalyst system to reduce CO and VOC. Operating exclusively with pipeline quality natural gas limits SOx and particulate matter emissions. Additionally, inlet air filters and lube oil vent filters would be used to minimize paritculate emissions. Appropriately sized stacks is also used to reduce ground-level concentrations of exhaust constituents.

Emission Offsets

In addition to emission control strategies included in the project design, SJVAPCD Rule 2201 requires A2PP to provide emission reduction credits to offset the new emissions of NOx, VOC and PM10. **Air Quality Table 18** summarizes the SJVAPCD Rule 2201 offset requirements for the A2PP, with offsets assumed to originate from shutdowns at sources located more than 15 miles away (distance offset ratio of 1.5-to-1). The SJVAPCD conducts a case-by-case analysis of requirements and distance ratios depending on the specific ERCs held by the applicant (SJVAPCD 2010).

AIR QUALITY Table 18
A2PP, SJVAPCD Offset Determination and Requirements (lb/yr)

Source	NOx	VOC	PM10	CO	SOx
Three CTGs	141,561	33,993	65,703	154,857	38,736
A2PP Potential to Emit	141,561	33,993	65,703	154,857	38,736
Offset Requirements					
Existing APP Potential Emissions	52,146	10,461	17,524	136,436	11,459
SJVAPCD Offset Threshold	20,000	20,000	29,200	200,000	54,750
Offsets Required by SJVAPCD for A2PP [a, b]	141,561	24,454	54,027	---	---
Offsets Required by SJVAPCD at A2PP [c]	212,342	36,682	81,042	---	---

Source: SJVAPCD 2010; Independent Staff Assessment.
Note: a. Emission offsets are not required for CO since the applicant has demonstrated to the satisfaction of the Air Pollution Control Officer (APCO) that the ambient air quality standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of the standards.
b. SJVAPCD's offsetting rules exempt sources that have potential emissions below the offset threshold, allowing a credit for VOC and PM10 from the existing APP in this case. This reduces the amount of offsets required by SJVAPCD for VOC and PM10 caused by A2PP. NOx emissions must be offset at the level of A2PP's potential to emit because existing APP's potential NOx emissions exceed the SVJAPCD offset threshold.
c. Includes a distance ratio factor of 1.5 for ERCs that would originate from sources over 15 miles away.

The proposed A2PP project would be required to surrender offsets according to the operating profile proposed by the applicant (AFC Appendix 5.1A, Tables 5.1A-4 and 5.1A-5, TID2009a). District conditions would limit the facility operation in terms of its quarterly and annual emissions (Conditions of Certification **AQ-31** to **AQ-36**), its daily emissions (**AQ-28** and **AQ-29**), and its short-term normal operation (**AQ-21** and **AQ-25**), rather than through its heat input rate or other parameters.

Emission Offsets for Ozone Impact

Air Quality Table 19 summarizes NOx and VOC offset requirements and identifies the sources of offsets proposed by TID. The applicant holds NOx and VOC ERCs that it intends to use to satisfy the District offset requirements. Both NOx and VOC emissions are recognized precursors to the formation of ambient ozone, and NOx is also a recognized precursor to the formation of the nitrate fraction of fine particulate matter.

AIR QUALITY Table 19
A2PP, NOx and VOC Offset Holdings and Quarterly Offset Requirements (lb/qtr)

Name of Offset / Site of Reduction	ERC Number	Q1 (lb/qtr)	Q2 (lb/qtr)	Q3 (lb/qtr)	Q4 (lb/qtr)
NOx Offsets Held by TID					
Elk Hills, Tupman, CA	S-3113-2	55,800	55,800	55,800	55,800
NOx Mitigation Total	---	**55,800**	**55,800**	**55,800**	**55,800**
Proposed NOx Emissions	---	**34,905**	**35,292**	**35,682**	**35,682**
NOx Fully Offset?	---	Yes	Yes	Yes	Yes
VOC Offsets Held by TID					
E North Ave, Fresno, CA	C-1008-1	10,250	10,250	10,250	10,250
VOC Mitigation Total	---	**10,250**	**10,250**	**10,250**	**10,250**
Proposed VOC Emissions	---	**8,382**	**8,475**	**8,568**	**8,568**
VOC Fully Offset?	---	Yes	Yes	Yes	Yes

Source: SJVAPCD 2010; Independent Staff Assessment.

TID appears to be in compliance with the District's NOx and VOC offset requirements and would provide overall total ERCs for ozone precursors at an offset ratio of greater than one-to-one, which satisfies the CEQA mitigation requirements for ozone impacts as established by Energy Commission staff in recent fossil fuel-fired power plant cases, such as Avenal Energy (08-AFC-1).

Emission Offsets for Particulate Matter Impact

Air Quality Table 20 summarizes PM10 offset requirements and identifies the sources of PM10 offsets proposed by TID. These offsets are held by TID and are being offered as mitigation for the PM10/PM2.5 impacts. TID would use its holdings of SOx ERCs through an interpollutant trade to satisfy the District offset requirements for PM10 (SJVAPCD 2010).

AIR QUALITY Table 20
A2PP, PM10 and SOx Offset Holdings and Quarterly Offset Requirements (lb/qtr)

Name of Offset / Site of Reduction	ERC Number	Q1 (lb/qtr)	Q2 (lb/qtr)	Q3 (lb/qtr)	Q4 (lb/qtr)
PM10 Offsets Held by TID					

No ERCs	---	---	---	---	---
Surplus SOx ERCs (to offset PM10)	(below)	46,065	30,493	10,496	54,910
Convert Q4 ERC to Q3	---	---	---	6,064	-6,064
PM10 Mitigation Total	---	**46,065**	**30,493**	**16,560**	**48,846**
Proposed PM10 Emissions	---	**16,200**	**16,383**	**16,560**	**16,560**
PM10 Fully Offset?	---	Yes	Yes	Yes	Yes
SOx Offsets Held by TID					
Panama Ln, Bakersfield	S-3129-5	55,614	40,150	0	84,936
Convert Q4 ERC to Q3	---	---	---	20,261	-20,261
SOx Mitigation Total	---	**55,614**	**40,150**	**20,261**	**64,675**
Proposed SOx Emissions	---	**9,549**	**9,657**	**9,765**	**9,765**
SOx Fully Offset?	---	Yes	Yes	Yes	Yes

Source: SJVAPCD 2010; Independent Staff Assessment.

The applicant proposes to use SOx ERC certificate to offset PM10/PM2.5 increases associated with the project. The SJVAPCD allows this by establishing an interpollutant offset ratio (District Rule 2201, Section 4.13.3). SOx is accepted as one of the major precursors of PM10 and PM2.5 through reaction with ammonia to form ammonium sulfates. Reductions in SOx, particularly in areas that are ammonia rich such as the San Joaquin Valley, can reduce secondary particulate formation. However, the key issue is determining the appropriate interpollutant offset ratio, which depends on the existing levels of particulate matter precursors and the general atmospheric chemistry of the area in question. The SJVAPCD conducted a district-wide analysis in March 2009 that is attached with the Final Determination of Compliance for A2PP (SJVAPCD 2010), and the district-wide analysis concluded that a one-to-one interpollutant ratio would be protective of managing regional PM10/PM2.5 impacts and progress towards attainment. However, the SJVAPCD's use of a one-to-one interpollutant ratio for Rule 2201 compliance leads to fewer SOx reductions for particulate matter than ratios used by SJVAPCD in some past cases. This issue is discussed further in **Cumulative Impacts and Mitigation**.

A2PP appears to be in compliance with the District's PM10 offset requirements and would provide overall total PM10/PM2.5 precursor ERCs at an offset ratio of greater than one-to-one, which satisfies the CEQA mitigation requirements for particulate matter impacts as established by Energy Commission staff in recent fossil fuel-fired power plant cases, such as Avenal Energy (08-AFC-1).

Adequacy of Proposed Mitigation

Energy Commission staff have long held that emission reductions need to be provided for all nonattainment pollutants and their precursors at a minimum overall one-to-one ratio of annual operating emissions. For this project, the District's offset requirements would meet or exceed that minimum offsetting goal for all ozone and particulate matter impacts.

The offsets shown in **Air Quality Table 19** and **Table 20** demonstrate that TID owns and would be required by the SJVAPCD to surrender ERCs in sufficient quantities to offset the project's NOx, VOC, PM10, and SOx emissions, per District requirements and Energy Commission staff policy. Although PM2.5 emissions are not required to be offset separately from PM10 emissions, staff notes that the annual total offsets for PM10 would fully offset PM2.5 emissions. How the offsets provide PM2.5 mitigation is discussed separately in **Secondary Pollutant Impacts**.

While the one-to-one interpollutant offset ratio for SOx and PM10 is lower than what has been historically required by the District on other cases, Energy Commission staff's longstanding position is that all nonattainment pollutant and precursor emissions must be offset by at least one-to-one. Therefore, the proposed emission offset package would mitigate all project air quality impacts to a less than significant level.

Staff's review of the offset package was determined solely based on the merits of this case, including the District offset requirements, the project's emission limits, the specific ERCs proposed, and ambient air quality considerations of the region, and does not in any way provide a precedence or obligation for the acceptance of offset proposals for any other current or future licensing cases.

Staff Proposed Mitigation

Staff proposes Conditions of Certification **AQ-SC6** to ensure that the license is amended as necessary to incorporate future changes to the air quality permits and to ensure ongoing compliance during commissioning and routine operation through quarterly reports (**AQ-SC8**). Staff also proposes a Condition of Certification (**AQ-SC7**) to ensure that significant impacts of ozone and PM10/PM2.5 precursors would be mitigated with the quantity of SJVAPCD offsets specified by staff and to ensure agency consultation if substitutions are made to the credits.

Cumulative Impacts and Mitigation

"Cumulative impacts" are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts" (CEQA Guidelines, §15355). Such impacts can be relatively minor and incremental yet still be significant because of the existing environmental background, particularly when considering other closely related past, present, and reasonably foreseeable future projects.

Criteria pollutants have impacts that are usually (though not always) cumulative by their nature. Rarely will a project itself cause a violation of a federal or state criteria pollutant standard. However, many new sources contribute to violations of criteria pollutant standards because of elevated background conditions. Air districts attempt to reduce background criteria pollutant levels by adopting attainment plans, which are multi-faceted programmatic approaches to attainment. Attainment plans typically include new source review requirements that provide offsets and use Best Available Control Technology, combined with more stringent emissions controls on existing sources.

The discussion of cumulative air quality impacts includes the following three analyses:

- a summary of projections for criteria pollutants by the air district and the air district's programmatic efforts to abate such pollution;
- an analysis of the project's "localized cumulative impacts" from direct emissions locally when combined with other local major emission sources; and

- a discussion of greenhouse gas emissions and global climate change impacts (in **AIR QUALITY APPENDIX AIR-1**).

Summary of Projections

The federal and California Clean Air Acts direct local air quality management agencies to implement plans and programs that lead to attainment and maintenance of the ambient air quality standards. The New Source Review program administered by SJVAPCD and other programs for reducing emissions from mobile sources or area-wide sources are part of air quality management plans.

Ozone

The **2004 Extreme Ozone Attainment Demonstration Plan** illustrates how the SJVAPCD would attain the federal 1-hour ozone standard that was revoked in 2005. This plan includes elements that are the foundation for later ozone plans.

The **2007 Ozone Plan** to attain the federal 8-hour ozone standard was approved by ARB on June 14, 2007. This plan would reduce ozone and particulate matter levels in the region, primarily by achieving a 75% reduction in NOx emissions by 2023. Achieving such dramatic reductions would affect all sectors of the region's economy (SJVAPCD 2007a). The plan relies on four main approaches: tighter District regulations for stationary sources, wider use of incentive-based measures (like the Carl Moyer Program) to accelerate deployment of cleaner sources, new "innovative" programs for trip-reduction and energy conservation, and expanded controls on mobile source tailpipe emissions.

The proposed A2PP is subject to the current SJVAPCD rules and regulations that specify performance standards, offset requirements, and emission control requirements for stationary sources. The regulations also include requirements for obtaining Authority to Construct (ATC) permits and subsequent operating permits. These regulations apply to A2PP and all other projects with emission sources. In general, triennial updates of the attainment plans ensure that population, employment, and transportation trends in the region are taken into account, and compliance with SJVAPCD rules and regulations ensures consistency with the regional air quality management plans. The SJVAPCD has demonstrated in its analysis of the offset requirements and other District rules that the proposed A2PP would be likely to comply with the recently adopted plans through regulatory compliance. Because the project would control ozone precursor emissions and use ERCs to fully offset ozone precursors as required by existing rules and regulations, the project would not be likely to conflict with the District's 2007 Ozone Plan or regional ozone attainment goals. This facility is likely to become operational before this ozone plan is updated, if this is needed due to changes in the federal ambient air quality ozone standard.

Particulate Matter

The **2007 PM10 Maintenance Plan** illustrates how the SJVAPCD intends to continue the efforts of the **2003 PM10 Plan** and **2006 PM10 Plan** that implemented aggressive PM10 controls in the region, including Reasonably Available Control Measures (RACM) for large existing sources of PM10 and fugitive dust. The 2007 PM10 Maintenance Plan includes a request for reclassification to "attainment" for the federal PM10 standard, and it provides for continued attainment for 10 year from the designation. In November 2008, the U.S. EPA redesignated the SJVAPCD to attainment for the federal PM10 standard (73 FR 66759, November 12, 2008).

The **2008 PM2.5 Plan** was adopted by the SJVAPCD Governing Board on April 30, 2008, and it includes measures for attaining the 1997 and 2006 federal PM2.5 standards. The 2008 PM2.5 Plan shows that emission reductions of NOx, directly emitted PM2.5, and SO_2 are needed to demonstrate attainment of the PM2.5 NAAQS in the San Joaquin Valley (p. 6-1 of plan).

Energy Commission staff ~~remains~~ raised concerns~~ed~~ that the proposed A2PP project could interfere with the attainment effort of the 2008 PM2.5 Plan if it relies on SOx emission reduction credits without an adequate trading ratio for allowing PM2.5 increases. The SJVAPCD has determined that the offset requirements would be satisfied so that no net increase of PM10 would occur (SJVAPCD 2010). Interpollutant trading is allowed with “the appropriate scientific demonstration of an adequate trading ratio” (Rule 2201, Section 4.13), and the SJVAPCD 2007 PM10 Maintenance Plan (see Appendix E of the Maintenance Plan) indicates that the minimum ratio would be one-to-one with higher interpollutant ratios if appropriate under Rule 2201. The one-to-one ratio was developed by the SJVAPCD based on modeling conducted in support of the 2008 PM2.5 Plan, but although implementation of trading under District Rule 2201 is subject to federal oversight, there is no evidence in the record indicating whether the methods used by the SJVAPCD in developing the ratio have been specifically reviewed and/or approved by U.S. Environmental Protection Agency.

The U.S. EPA review of the SJVAPCD’s 2008 PM2.5 Plan is ongoing, and the review may eventually lead to future projects in the region being subject to a different ~~conclusion on an appropriate~~ interpollutant trading ratio ~~for the SJVAPCD~~. Although there is no formal federal endorsement of the District’s interpollutant trading approach, ~~Energy Commission staff is able to conclude that the A2PP project would not be likely to conflict with regional particulate matter attainment goals. Staff recognizes that~~ the attainment plan has been previously adopted by ARB, and the SJVAPCD has determined (SJVAPCD 2010) that the interpollutant trading ratio is appropriate. The SJVAPCD shows that A2PP is likely to comply with the particulate matter plans by meeting its permit requirements and complying with the existing applicable rules and regulations. With this information, staff is able to conclude that the A2PP project would not be likely to conflict with regional particulate matter attainment goals.

Localized Cumulative Impacts

The proposed project and other reasonably foreseeable projects could cause impacts that would be locally combined if present and future projects would introduce stationary sources that are not included in the “background” conditions. Under CEQA, reasonably foreseeable future projects are usually those that are either currently under construction or in the process of being approved by a local air district or municipality. Projects that have not yet entered the approval process do not ordinarily qualify as “foreseeable” since the detailed information needed to conduct this analysis is not available. Sources that are presently operational are included in the background concentrations. Background conditions also take into account the effects of non-stationary sources.

Projects with stationary sources located up to six miles from the proposed project site usually need to be considered by the analysis. TID requested that the SJVAPCD identify potential new stationary sources within six miles of the A2PP (Response to Workshop Queries and DR 8 and 9, CH2M2009f). The SJVAPCD reported 72 exsisting facilities and 159 proposed projects. In addition to the Almond Power Plant and A2PP, only five projects would involve emissions increases of more than 10 pounds per day of any contaminant other than VOC. Although cumulative sources emitting exclusively VOC would contribute to the project-related impacts to secondary ozone formation, these impacts are not modeled in this Staff Assessment because there are no agency-recommended models or procedures for quantifying the cumulative ozone impacts.

The A2PP cumulative analysis considers the existing Almond Power Plant (AFC Appendix 5.1G, TID2009a), and the SJVAPCD response on foreseeable sources identified the following facilities and stationary sources (Response to DR 8 and 9):

- **Existing APP.** The existing APP, adjacent to the proposed A2PP, would experience a reduction in operation (Response to DR 2 and 15, CH2M2009f). However, the existing APP stationary sources included in A2PP's analysis of cumulative impacts is based on current operational patterns, results shown in **Air Quality Table 21**.
- **Facility #N-1090522 (Stanislaus County Bldg. Maint.).** Proposed a 900 hp Caterpillar Model C27 diesel-fired emergency standby IC engine.
- **Facility #N-1081108 (Conagra Foods).** Proposed a new vegetable branding and roasting operation served by one 0.576 MMBtu/hr natural gas fired ribbon burner (branding) and five 0.576 MMBtu/hr natural gas fired ribbon burners (roasting).
- **Facility #N-1804279 (Ceres Memorial Park).** Proposed a new Hartwick Combustion Technologies, Inc. Model APEX-250 crematory incinerator consisting of a 0.6 MMBtu/hr primary burner and a 1.2 MMBtu/hr secondary burner (afterburner).
- **Facility #N-1801297 (Winco Foods).** 1) Proposed a 480 hp Caterpillar Model C9 Tier 3 certified diesel-fired emergency standby IC engine powering an electric generator. 2) Proposed a 1,372 hp Caterpillar Model C32 Tier 2 certified diesel-fired emergency standby IC engine powering an electric generator~~, respectively~~.

The maximum modeled cumulative impacts are presented below in **Air Quality Table 21**. The total impact is conservatively estimated by the maximum modeled impact plus existing maximum background pollutant levels.

AIR QUALITY Table 21
A2PP, Ambient Air Quality Impacts from Cumulative Sources (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	LimitingStandard	Percent of Standard
PM10	24 hour	8.2	**111.1**	**119.3**	50	**239**
	Annual	1.4	**31.7**	**33.1**	20	**166**
PM2.5	24 hour	8.2	**71**	**79.2**	35	**226**
	Annual	1.4	**16.0**	**17.4**	12	**145**
CO	1 hour	66.1	7,935	8,001.1	23,000	35
	8 hour	144.7	4,144	4,288.7	10,000	43

NO_2 [a]	1 hour-[a]	167.0	118.7	285.7	339	84
	1 hour Federal	50.2 [b]	93.8	144.0	188	77
	Annual	0.6	24.7	25.3	57	44
SO_2	1 hour	3.6	47.2	50.8	655	8
	1 hour Federal	3.6	47.2	50.8	196	26
	24 hour	1.5	18.4	19.9	105	19
	Annual	0.5	5.3	5.8	80	7

Source: Response to DR 8 and 9 (CH2M2009f), with independent staff assessment for NO_2, December 2009.
Notes:
a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output.
b. Non-facility emergency-use-only standby engines are not modeled in the compliance demonstration for 1-hour federal NO_2 standard.

Compared with the impacts from the proposed A2PP project alone, maximum cumulative impacts caused by the existing APP would be substantially higher for PM10/PM2.5. The combined PM10/PM2.5 impacts caused by A2PP, the existing APP and other projects would be dominated by A2PP. Although the propsed A2PP causes higher cumulative impacts than the existing APP for NO_2, the total NO_2 impacts would be dominated by the other unrelated projects. Modeled concentrations of 1-hour NO_2 are highest at the other cumulative sources, especially at internal combustion engines proposed for emergency use at neighboring facilities. In the immediate vicinity (few hundred meters) of these off-site emergency standby engines, maximum 1-hour NO_2 concentrations could potentially exceed~~ing~~ the newly-established~~, but not yet effective,~~ federal 1-hour NO_2 standard. However, compliance with this new standard is not based upon maximum 1-hour concentrations, but rather it relies on multi-year data. When viewed over a multi-year period, NO_2 impacts caused by neighboring sources that operate only for testing and emergency purposes would not be likely to cause a new violation. The proposed A2PP, with the existing APP, would not cause or contribute to a violation because maximum 1-hour NO_2 modeled impacts excluding the neighboring off-site emergency generator engines would be approximately 50 μg/m^3 and in compliance with new standard.

Staff believes that particulate matter emissions from A2PP would be cumulatively considerable because they would contribute to existing violations of the PM10 and PM2.5 ambient air quality standards. Secondary impacts would also be cumulatively considerable for PM10, PM2.5, and ozone because emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would contribute to existing violations of the PM10, PM2.5, and ozone standards. To address the contribution caused by A2PP to cumulative particulate matter and ozone impacts, mitigation would offset all nonattainment pollutants and their precursors at a minimum ratio of one-to-one.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The Preliminary Determination of Compliance (PDOC) for A2PP was dated December 2, 2009 (SJVAPCD 2009c) and the Final Determination of Compliance (FDOC) was released and dated February 16, 2010 (SJVAPCD 2010). Compliance with all District Rules and Regulations was demonstrated to the SJVAPCD's satisfaction in the PDOC and FDOC, and the FDOC conditions are presented in the Conditions of Certification. The applicant filed only minor comments on the PDOC.

FEDERAL

40 CFR 51, Nonattainment New Source Review. The FDOC includes conditions that would implement the federal nonattainment New Source Review (NSR) permit for A2PP.

40 CFR 52.21, Prevention of Significant Deterioration. The A2PP project would not be subject to permit requirements under the Prevention of Significant Deterioration (PSD) program because A2PP would not qualify as a new major stationary source of NO_2, CO, or PM10. If, in the future, the project owner changes the project, staff proposes Condition of Certification **AQ-SC6** to ensure that the owner promptly notifies the Energy Commission to incorporate changes in permit conditions, if any.

40 CFR 60, NSPS Subpart KKKK. The three CTGs proposed for A2PP would be likely to comply with the applicable emission limits by achieving a NOx emission rate of 2.5 ppmvd over any one-hour period except during startup and shutdown periods and during combustor tuning.

STATE

A2PP has demonstrated that the project would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury. Compliance with the FDOC (SJVAPCD 2010) and the Energy Commission staff's Conditions of Certification enable staff's affirmative finding.

LOCAL

The SJVAPCD issued the PDOC (SJVAPCD 2009c) and FDOC (SJVAPCD 2010) stating that the proposed project is expected to comply with all applicable District rules and regulations. The District rules and regulations specify the emissions control and offset requirements for the new sources associated with A2PP. The SJVAPCD has determined that the project would use the Best Available Control Technology (BACT), and the emission reduction credits (ERCs) approved and certified by the District would fully offset project nonattainment pollutant (including precursors) emissions so that they would be consistent with District rules and regulations.

SJVAPCD Rules 2201 and 2301, New Source Review and Offsets. Staff identified concerns on whether the ERCs would be exchanged with an interpollutant ratio that is consistent with U.S. EPA recommendations, as discussed under **Air Quality Cumulative Impacts**. Future projects may be subject to different interpollutant offset ratios than those found acceptable for this project because the U.S. EPA review of the SJVAPCD's 2008 PM2.5 Plan is ongoing.

CONCLUSIONS

- Construction impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC5** to mitigate the project construction-phase impacts to a less than significant level.

- Operation of the project would comply with applicable SJVAPCD rules and regulations, including New Source Review, Best Available Control Technology (BACT) requirements, and requirements to offset emission increases.
- The project would neither cause new violations of any NO_2, CO, or SO_2 ambient air quality standards nor contribute to existing violations for these pollutants. Therefore, the project's direct NO_2, CO, and SO_2 impacts are less than significant. ~~However, this assessment does not include evaluation of this project's compliance with the 2010 federal 1-hour NO_2 standard because the standard was promulgated after this application was filed, and there is a corresponding lack of guidance and modeling tools for conducting impact analyses and determining existing background concentrations for compliance with this standard.~~
- The project NOx and VOC emissions would contribute to existing violations of state and federal ozone ambient air quality standards. The ozone precursor offsets required by SJVAPCD and shown in Condition of Certification **AQ-SC7** would mitigate the ozone impact to a less than significant level.
- The project PM10 and PM2.5 emissions and the PM10/PM2.5 precursor emissions of SOx would contribute to the existing violations of state and federal PM10 and PM2.5 ambient air quality standards. The SJVAPCD requirements to offset PM10 would be satisfied by surrendering SOx ERCs under an interpollutant exchange, and these ERCs would mitigate the PM10/PM2.5 impacts to a less than significant level. The offsets would be in sufficient quantities to satisfy Energy Commission staff's longstanding position that all nonattainment pollutant and precursor emissions be offset at least one-to-one. Future projects may be subject to different interpollutant offset ratios because the U.S. EPA review of the SJVAPCD's 2008 PM2.5 Plan is ongoing, and there is no evidence that the District's interpollutant trading ratios have been specifically reviewed and/or approved by U.S. EPA (see **Cumulative Impacts and Mitigation**).
- ~~Staff recommends Condition of Certification **AQ-SC9** to limit ammonia slip from the simple-cycle system to the extent feasible.~~
- Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **Air Quality Appendix AIR-1**. The A2PP would exceed the Emission Performance Standard established by SB 1368 for base load generation. However, as a simple-cycle power plant, A2PP is not designed or intended for base load generation and is therefore not subject to the Emission Performance Standard. The project would be subject to the Air Resources Board mandatory GHG reporting requirements and any GHG reduction or trading requirements developed by the ARB as GHG regulations are implemented.

PROPOSED CONDITIONS OF CERTIFICATION

Staff-Recommended Conditions of Certification

Staff proposes the following conditions of certification (identified as the **AQ-SCx** series of conditions) to provide mitigation during the construction phase of the project.

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with conditions **AQ-SC3, AQ-SC4** and **AQ-SC5** for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM delegates. The AQCMM and AQCMM delegates shall have full access to all areas of construction on the project site and linear facilities, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the compliance project manager (CPM).

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM delegates. The AQCMM and all delegates must be approved by the CPM before the start of ground disturbance.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide, for approval, an AQCMP that details the steps to be taken and the reporting requirements necessary to ensure compliance with conditions of certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5**.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. The AQCMP must be approved by the CPM before the start of ground disturbance.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each monthly compliance report (MCR) that demonstrates compliance with the following mitigation measures for purposes of preventing all fugitive dust plumes from leaving the project site and linear facility routes. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

a. All unpaved roads and disturbed areas in the project and linear construction sites shall be watered as frequently as necessary to comply with the dust mitigation objectives of **AQ-SC4**. The frequency of watering may be either reduced or eliminated during periods of precipitation.

b. No vehicle shall exceed 15 miles per hour within the construction site.

c. The construction site entrances shall be posted with visible speed limit signs.

d. All construction equipment vehicle tires shall be inspected and washed as necessary to be free of dirt prior to entering paved roadways.

~~e. Gravel ramps of at least 20 feet in length must be provided at the tire~~

~~washing/cleaning station.~~

f. ~~All~~ Any unpaved exits from the construction site shall include a control device ~~be graveled or treated~~ to prevent track-out to paved public roadways, using one or more of the following techniques: a grizzly (rails, pipes, or grates used to dislodge debris from vehicles before they exit the site) that extends from the intersection with the paved road surface for the full width of the unpaved exit surface for a distance of at least 25 feet; or a layer of washed gravel at least one inch or larger in diameter and three inches deep, extending from the intersection with the paved road surface for the full width of the unpaved exit surface for a distance of at least 50 feet; or at least 100 feet of paved surface which extends from the intersection with the paved public road surface for the full width of the unpaved access road; or an alternative trackout control device approved by the District and the CPM.

g. All construction vehicles shall enter the construction site through the treated entrance roadways unless an alternative route has been submitted to and approved by the CPM.

h. Construction areas adjacent to any paved roadway shall be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.

i. All paved roads within the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

j. At least the first 500 feet of any ~~public~~ paved roadway exiting from the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or run-off from the construction site is visible on the ~~public~~ paved roadways.

k. All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered or treated with appropriate dust suppressant compounds.

l. All vehicles that are used to transport solid bulk material on public roadways and that have the potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks to provide at least two feet of freeboard.

m. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

Verification: The project owner shall include in the MCR: (1) a summary of all actions taken to maintain compliance with this condition; (2) copies of any complaints filed with the air district in relation to project construction; and (3) any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes with the potential to be transported off the project site, 200 feet beyond the centerline of the construction of linear facilities, or within 100 feet upwind of any regularly occupied structures not owned by the project owner indicate that existing mitigation measures are not providing effective mitigation. The AQCMM or delegate shall then implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed.

Step 1: Within 15 minutes of making such a determination, the AQCMM or delegate shall direct more intensive application of the existing mitigation methods.

Step 2: If Step 1 specified above fails to result in adequate mitigation within 30 minutes of the original determination, the AQCMM or delegate shall direct implementation of additional methods of dust suppression.

Step 3: If Step 2 specified above fails to result in effective mitigation within one hour of the original determination, the AQCMM or delegate shall direct a temporary shutdown of the activity causing the emissions. The activity shall not restart until the AQCMM or delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or delegate to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMP shall include a section detailing how additional mitigation measures will be accomplished within the specified time limits.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the MCR, a construction mitigation report that demonstrates compliance with the following mitigation measures for purposes of controlling diesel construction-related emissions. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

a. All diesel-fueled engines used in the construction of the facility shall have clearly visible tags, issued by the on-site AQCMM, showing that the engine meets the conditions set forth herein.

b. All construction diesel engines with a rating of 50 hp or higher shall meet, at a minimum, the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines, as specified in California Code of Regulations, Title 13, section 2423(b)(1), unless certified by the on-site AQCMM that such engine is not available for a particular item of equipment. This good faith effort shall be documented with signed written correspondence by the appropriate construction contractors, along with documented correspondence with at least two construction equipment rental firms. In the event that a Tier 3 engine is not available for any off-road equipment larger than 50 hp, that equipment shall be equipped with a Tier 2 engine or an engine that is equipped with retrofit controls to reduce exhaust emissions of nitrogen oxides (NOx) and diesel particulate matter (DPM) to no more than Tier 2 levels, unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is “not practical” for the following, as well as other, reasons:

   1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question to Tier 2 equivalent emission levels and either a Tier 1 engine or the highest level of available control is being used; or
   2. The construction equipment is intended to be on site for five days or less.
   3. The CPM may grant relief from this requirement if the AQCMM can demonstrate a good faith effort to comply with this requirement and that compliance is not possible.
   4. Equipment owned by specialty subcontractors may be granted an exemption, for single equipment items on a case-by-case basis, if it can be demonstrated that extreme financial hardship would occur if the specialty subcontractor had to rent replacement equipment, or if it can be demonstrated that a specialized equipment item is not available by rental.

c. The use of a retrofit control device may be terminated immediately, provided that the CPM is informed within 10 working days of the termination and the AQCMM demonstrates that one of the following conditions exists:

   1. The use of the control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive

increase in back pressure.

2. The control device is causing or is reasonably expected to cause significant engine damage.
3. The control device is causing or is reasonably expected to cause a significant risk to workers or the public.
4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

d. All heavy earth-moving equipment and heavy duty construction-related trucks with engines meeting the requirements of (b) above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

e. All diesel heavy construction equipment shall not idle for more than five minutes, to the extent practical.

f. Construction equipment will employ electric motors when feasible.

Verification: The project owner shall include in the MCR: (1) a summary of all actions taken to maintain compliance with this condition; (2) a list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that the equipment has been properly maintained; and (3) any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC6 The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. EPA, and any revised permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any proposed air permit modification to the CPM within five working days of either: 1) submittal by the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-SC7 The project owner shall provide emission reductions in the form of offsets or emission reduction credits (ERCs) in the quantities of at least 141,561 lb NOx, 33,993 lb VOC, 65,703 lb PM10, and 38,736 lb SOx emissions. The project owner shall demonstrate that the reductions are provided in the form required by the District.

The project owner shall surrender the ERCs from among those that are listed in the District Final Determination of Compliance Conditions (SJVAPCD 2010) or a modified list, as allowed by this condition. If additional ERCs are submitted, the project owner shall submit an updated table including the additional ERCs to the CPM. The project owner shall request CPM approval for any substitutions, modifications, or additions to the listed credits.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, and that the requested change(s) will not cause the project to result in a significant environmental impact. The District must also confirm that each requested change is consistent with applicable federal and state laws and regulations.

Verification: The project owner shall submit to the CPM records showing that the project's offset requirements have been met prior to initiating construction. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and the Energy Commission docket. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-SC8 The project owner shall submit to the CPM quarterly operation reports that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification. The quarterly operation report shall specifically note or highlight incidences of noncompliance.

Verification: The project owner shall submit quarterly operation reports to the CPM and APCO no later than 30 days following the end of each calendar quarter. This information shall be maintained on site for a minimum of five years and shall be provided to the CPM and District personnel upon request.

~~**AQ-SC9** The ammonia (NH3) emissions from each combustion turbine (N-3299-4-0, '-5-0, -6-0) shall not exceed 10.0 ppmvd @ 15% O2 averaged over a 24 hour rolling average. In addition, the selective catalytic reduction (SCR) system catalyst shall be replaced, repaired, or otherwise reconditioned within 12 months if the ammonia slip exceeds 5 ppmvd @ 15% O2 over a 24 hour rolling average. The SCR ammonia injection grid replacement, repair, or reconditioning scheduled event may be cancelled if the owner or operator can demonstrate that, subsequent to the initial exceedance, the ammonia slip consistently remains below 5 ppmvd @ 15% O2 averaged over 24 hours, and that the initial exceedance does not accurately indicate expected future operating conditions.~~

~~**Verification:** The ammonia injection rate shall be monitored, and ammonia emissions calculated and recorded hourly (**AQ-26** and **AQ-27**). A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).~~

District Final Determination Of Compliance Conditions (SJVAPCD 2010)

The following conditions, **AQ-1** to **AQ-64**, apply to each of the three LM6000 PG SPRINT CTGs individually, and conditions **AQ-65** to **AQ-95** apply to the proposed

A2PP facility as a whole. The SJVAPCD released its Final Determination of Compliance dated February 16, 2010, and this staff assessment reflects the SJVAPCD conditions.

EQUIPMENT DESCRIPTION, UNITS N-3299-4-0, N-3299-5-0, and N-3299-6-0

54.2 MW nominal (ISO) rating simple-cycle peak-demand power generating system consisting of a 523.2 MMBTU/HR (at nominal ISO MW rating) General Electric, aero derivative, model LM6000 PG Sprint, natural gas-fired combustion turbine generator with a water spray premixed combustion system, an oxidation catalyst and a selective catalytic reduction (SCR) system with ammonia injection.

AQ-1 The permittee shall not begin actual on-site construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-2 This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

Verification: No verification necessary.

AQ-3 Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

Verification: The project owner shall submit to both the District and CPM the Title V Operating Permit application prior to operation.

AQ-4 The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ SC8**).

AQ-5 The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-6 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-7 The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-8 Particulate matter emissions from the gas turbine system shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Verification: The project owner shall submit the results of source tests to both the District and CPM in accordance with **AQ-46**.

AQ-9 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-10 APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-11 Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbine and associated electrical delivery systems. [District Rule 2201]

Verification: No verification necessary.

AQ-12 Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial source testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

Verification: The project owner shall submit a commissioning plan to the CPM and APCO for approval at least 30 days prior to first firing of the gas turbine describing the procedures to be followed during the commissioning period and the anticipated duration of each commissioning activity.

AQ-13 Emission rates from the gas turbine system during the commissioning period shall not exceed any of the following limits: NOx (as NO2) - 40.40 lb/hr and 969.6 lb/day; VOC (as CH4) - 8.41 lb/hr and 201.8 lb/day; CO - 40.00 lb/hr and 704.6 lb/day; PM10 - 2.50 lb/hr and 60.0 lb/day; or SOx (as SO2) - 1.56 lb/hr and 37.4 lb/day. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-14 During commissioning period, NOx and CO emission rate shall be monitored using installed and calibrated Continuous Emission Monitoring Systems (CEMS). [District Rule 2201]

Verification: The project owner shall submit to the CPM and APCO for approval the commissioning plan as required in **AQ-12**.

AQ-15 The total mass emissions of NOx, VOC, CO, PM10 and SOx that are emitted during the commissioning period shall accrue towards the quarterly emission limits. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-16 During commissioning period, the owner or operator shall keep records of the natural gas fuel combusted in the gas turbine system on an hourly and daily basis. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-17 Startup of this gas turbine system shall not exceed one hour per event. [District Rules 2201 and 4703]

Verification: The project owner shall submit to the District and CPM the startup event duration data demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-18 Shutdown of this gas turbine system shall not exceed one hour per event. [District Rules 2201 and 4703]

Verification: The project owner shall submit to the District and CPM the shutdown event duration data demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-19 During all types of operation (with an exception of ammonia injection tuning prior to the initial source test during the commissioning period), including startup and shutdown periods, ammonia injection into the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-20 The District shall administratively add the minimum temperature limitation established pursuant to the above condition in the final Permit to Operate. The District may administratively modify the temperature as necessary following any replacement of the SCR catalyst material. [District Rule 2201]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-21 During start-up or shutdown period, the emissions shall not exceed any of the following limits: NOx (as NO2) - 25.00 lb/hr; CO - 40.00 lb/hr; VOC (as methane) - 2.00 lb/hr; PM10 - 2.50 lb/hr; SOX (as SO2) - 1.56 lb/hr; or NH3 - 7.44 lb/hr. [District Rules 2201 and 4703]

<u>Verification:</u> A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-22 Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703, 3.29]

<u>Verification:</u> No verification necessary.

AQ-23 Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status ending when the fuel supply to the unit is completely turned off. [District Rule 4703, 3.26]

<u>Verification:</u> No verification necessary.

AQ-24 The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703, 5.3.2]

<u>Verification:</u> The project owner shall submit to the District and CPM the startup and shutdown event duration data demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-25 Except during startup and shutdown periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 5.02 lb/hr and 2.5 ppmvd @ 15% O2; CO - 4.89 lb/hr and 4.0 ppmvd @ 15% O2; VOC (as methane) - 1.40 lb/hr and 2.0 ppmvd @ 15% O2; PM10 - 2.50 lb/hr; or SOx (as SO2) - 1.56 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-26 NH3 emissions shall not exceed 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-27 Each 3-hour rolling average period will be compiled from the three most recent one hour periods. Each one hour period shall commence on the hour. Each one hour period in a twenty-four hour rolling average for ammonia slip will commence on the hour. The twenty-four hour rolling average shall be calculated using the most recent twenty-four one-hour periods. [District Rule 2201]

Verification: No verification necessary.

AQ-28 Emissions from the gas turbine system, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) - 160.4 lb/day; CO - 187.6 lb/day; VOC - 34.8 lb/day; PM10 - 60.0 lb/day; SOx (as SO2) - 37.4 lb/day, or NH3 - 178.6 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-29 Emissions from the gas turbine system, on days when a startup and/or shutdown does not occur, shall not exceed the following: NOx (as NO2) - 120.5 lb/day; CO - 117.4 lb/day; VOC - 33.6 lb/day; PM10 - 60.0 lb/day; SOx (as SO2) - 37.4 lb/day, or NH3 - 178.6 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-30 Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

__**Verification:**__ The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-31 NOx (as NO2) emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 11,635 lb; 2nd quarter: 11,764 lb; 3rd quarter: 11,894 lb; 4th quarter: 11,894 lb. [District Rule 2201]

__**Verification:**__ A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-32 CO emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 12,728 lb; 2nd quarter: 12,869 lb; 3rd quarter: 13,011 lb; 4th quarter: 13,011 lb. [District Rule 2201]

__**Verification:**__ A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-33 VOC emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 2,794 lb; 2nd quarter: 2,825 lb; 3rd quarter: 2,856 lb; 4th quarter: 2,856 lb. [District Rule 2201]

__**Verification:**__ A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-34 NH3 emissions from the SCR system associated with this gas turbine system shall not exceed any of the following: 1st quarter: 15,181 lb; 2nd quarter: 15,349 lb; 3rd quarter: 15,517 lb; 4th quarter: 15,517 lb. [District Rule 2201]

__**Verification:**__ A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-35 PM10 emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 5,400 lb; 2nd quarter: 5,461 lb; 3rd quarter: 5,520 lb; 4th quarter: 5,520 lb. [District Rule 2201]

__**Verification:**__ A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-36 SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 3,183 lb; 2nd quarter: 3,219 lb; 3rd quarter: 3,255 lb; 4th quarter: 3,255 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-37 A water injection system, a selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine system. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-38 The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators or equivalent technology sufficient to limit the visible emissions from the lube oil vents to not exceed 5% opacity, except for a period not exceeding three minutes in any one hour. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-39 Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

Verification: The project owner shall submit the proposed source test plan or protocol for the source tests 15 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 30 days prior to the proposed source test date and time.

AQ-40 Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-39**.

AQ-41 Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted before the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081]

Verification: The results and field data collected during source tests shall be submitted to the District and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-39**). Testing for startup and shutdown emissions shall be conducted upon initial operation and at least once every seven years.

AQ-42 Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted before the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)]

Verification: The results and field data collected during source tests shall be submitted to the District and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-39**). Testing for steady-state emissions shall be conducted upon initial operation and at least once every 12 months.

AQ-43 The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored within 60 days after the end of commissioning period and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Verification: The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**)~~The results and field data collected during source tests shall be submitted to the District and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-39**). Testing for steady-state emissions shall be conducted upon initial operation and at least once every 12 months~~.

AQ-44 The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703, 40 CFR 60.4400(1)(i)]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-39**.

AQ-45 Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Verification: The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-46 The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Verification: The project owner shall submit the report of the source test results to both the District and CPM within 60 days of the last day of tests.

AQ-47 A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 4703]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-48 The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O2 concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission to verify the continuous monitoring system is properly installed and operational.

AQ-49 The NOx and O2 CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-50 The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-51 The CEMS data shall be reduced to hourly averages as specified in §60.13(h) and in accordance with §60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350]

Verification: The project owner shall submit to the CPM and APCO CEMS data reduced in compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-52 In accordance with 40 CFR Part 60, Appendix F, 5.1, the CO CEMS must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-53 The owner/operator shall perform a RATA for CO as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-54 The NOx and O2 CEMS shall be audited in accordance with the applicable requirements of 40 CFR Part 75. Linearity reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-55 Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission upon request.

AQ-56 The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080]

Verification: The project owner shall provide a Continuous Emission Monitoring System (CEM) protocol for approval by the APCO and CPM at least 60 days prior to installation of the CEM. The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission upon request.

AQ-57 The owner or operator shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.7(b)]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-58 The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission upon request.

AQ-59 Monitor Downtime is defined as any unit operating hour in which the data for NOx, or O2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)]

Verification: No verification necessary.

AQ-60 The owner or operator shall maintain records of the following items: 1) hourly and daily emissions, in pounds, for each pollutant listed in this permit on the days startup and or shutdown of the gas turbine system occurs, 2) hourly and daily emissions, in pounds, for each pollutant in this permit on the days startup and or shutdown of the gas turbine system does not occur, 3) quarterly emissions, in pounds, for each pollutant listed in this permit. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-61 The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, total hours of operation, the type and quantity of fuel used, date/time and duration of each start-up and each shutdown event. [District Rule 2201 and 4703, 6.2.6, 6.2.8, 6.2.11]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-62 The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201 and 4703, 6.2.4]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-63 The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Verification: The project owner shall submit to the District and CPM the report of CEM operations, emission data, and monitor downtime data in the quarterly operation report (**AQ-SC8**) that follows the definitions of this condition.

AQ-64 The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5]

Verification: The project owner shall submit to the District and CPM the report of CEM operations, emission data, and monitor downtime data in the quarterly operation report (**AQ-SC8**).

AQ-65 Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of NOx: 1st quarter: 34,905 lb, 2nd quarter: 35,292 lb, 3rd quarter: 35,682 lb, and 4th quarter: 35,682 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-66 NOx ERC S-3113-2 (or a certificate split from this certificate) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-67 Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of VOC: 1st quarter: 6,113 lb, 2nd quarter: 6,113 lb, 3rd quarter: 6,114 lb, and 4th quarter: 6,114 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-68 VOC ERC C-1008-1 (or a certificate split from this certificate) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-69 Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of PM10: 1st quarter: 13,506 lb, 2nd quarter: 13,507 lb, 3rd quarter: 13,507 lb, and 4th quarter: 13,507 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-70 SOx ERC S-3129-5 (or a certificate split from this certificate) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-71 The District has authorized to use SOx reductions to offset emissions increase in PM10 at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201]

Verification: No verification necessary.

AQ-72 Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

Verification: A summary of significant construction activities and monitoring records required shall be included in the construction monthly compliance report (**AQ-SC3**).

AQ-73 An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

Verification: The final Dust Control Plan shall be included within the Air Quality Construction Mitigation Plan and submitted to the District and CPM not less than 30 days prior to the start of any construction activity~~(**AQ-SC2**)~~, and a summary of significant construction activities and monitoring records required shall be included in the construction monthly compliance report (**AQ-SC3**).

AQ-74 An owner/operator shall prevent or clean up any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 or Rule 8011. [District Rules 8011 and 8041]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-75 Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-76 Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-77 Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-78 Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-79 On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-80 Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-81 Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031 and 8071]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-82 The owners and operators of each affected source and each affected unit at the source shall have an Acid Rain permit and operate in compliance with all permit requirements. [40 CFR 72]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request ~~submit to both the District and CPM the Acid Rain Program application after completing commissioning~~.

AQ-83 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-84 The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-85 The owners and operators of each source and each affected unit at the source shall: (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-86 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77]

Verification: No verification necessary.

AQ-87 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-88 An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-89 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72]

Verification: No verification necessary.

AQ-90 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72]

Verification: No verification necessary.

AQ-91 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77]

Verification: The project owner shall submit to both the District and CPM the proposed offset plan as required by the federal rule.

AQ-92 The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) Pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-93 The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-94 The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 75]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-95 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request ~~submit to both the District and CPM the Acid Rain Program application after completing commissioning~~.

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AIR QUALITY APPENDIX AIR-1

Greenhouse Gas Emissions

Testimony of Tao Jiang and Brewster Birdsall, P.E., QEP

SUMMARY OF CONCLUSIONS

The Almond 2 Power Plant (A2PP) project is a proposed addition to the state's electricity system. It would be an efficient, new, dispatchable natural gas-fired simple-cycle power plant that would produce greenhouse gas (GHG) emissions while generating electricity for California consumers. Its addition to the system would displace other less efficient and less flexible plants and facilitate the integration of renewable resources. Because the project will improve the efficiency of existing system resources and provide quick starting and fast ramping power suitable for integrating renewable generation, the addition of A2PP would contribute to a reduction of the California and overall Turlock Irrigation District (TID) system GHG[2] emissions and GHG emission rate average.

Staff notes that mandatory reporting of the GHG emissions provides the necessary information for the California Air Resources Board (ARB) to develop greenhouse gas regulations and/or trading markets required by the California Global Warming Solutions Act of 2006 (AB 32 Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.). The project may be subject to additional reporting requirements and GHG reductions or trading requirements as these regulations are more fully developed and implemented.

The Energy Commission adopted an order initiating an informational (OII) proceeding (08-GHG OII-1) to explore methods of assessing the greenhouse gas impacts of proposed new power plants in accordance with the California Environmental Quality Act (CEQA). This analysis provides the staff's conclusions regarding greenhouse gas emissions for this siting case. Future power plant siting cases are likely to be reviewed with the benefit of new information and policy direction from the Energy Commission and other agencies including ARB. This analysis recognizes that "prudent use" of natural gas for electricity generation will serve to optimize the system (for integrating intermittent renewable generation and providing reliability), but, without further analysis and policy direction by the Commission to refine this general understanding, this analysis leaves the implications for optimizing the system to future cases (CEC 2009a).

The operation of A2PP would affect the overall electricity system operation and GHG emissions in several ways:

- A2PP would provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.

[2] Fuel-use closely correlates to carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from the fuel combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

- A2PP would operate at a low heat rate to displace some less efficient and less flexible local generation in the dispatch order of gas-fired facilities that are required to provide electricity reliability in the TID system.
- A2PP would facilitate to some degree the replacement of out-of-state coal electricity generation that must be phased out in conformance with the State's new Emissions Performance Standard.
- A2PP could facilitate to some extent the replacement of generation provided by aging power plants that use once-through cooling.

The proposed A2PP would be designed to provide flexible, dispatchable power with simple-cycle units that are quick-starting and fast-ramping. The project would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff believes that the project would result in a net reduction in GHG emissions from power plants, would not worsen, but would improve, current conditions, and would, thus, not result in impacts that are cumulatively significant.

Staff concludes that the short-term emission of greenhouse gases during construction would be sufficiently reduced by "best practices" and would not be significant.

The project would not be subject to the limits of the greenhouse gas Emission Performance Standard (EPS) (Title 20, California Code of Regulations, Section 2900 et seq.) because A2PP is a simple-cycle power plant, designed and intended to provide electricity at an annualized plant capacity factor of less than 60% (CH2M2009h).

INTRODUCTION

Greenhouse gas (GHG) emissions are not criteria pollutants, but they are discussed in the context of cumulative impacts. In December 2009, the U.S. Environmental Protection Agency (EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the American people (the endangerment finding), and this became effective on January 14, 2010. Regulating GHG at the federal level may be furthered by the Prevention of Significant Deterioration (PSD) program and New Source Review (NSR) rule changes proposed by U.S. EPA on September 30, 2009. These requirements could eventually apply to new facilities whose carbon dioxide-equivalent emissions exceed 25,000 tons per year (U.S.EPA2009c). Federal rules that became effective December 29, 2009 (40 CFR 98) already require reporting of GHG. As federal rulemaking evolves, staff focuses on analyzing the ability of the project to comply with existing state-level policies and programs for GHG. The state has demonstrated its intent to address global climate change though research, adaptation,[3] and GHG inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

[3] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state's climate (for example, changing rainfall patterns).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies in **Greenhouse Gas Table 1** pertain to the control and mitigation of greenhouse gas emissions. Staff's analysis examines the project's compliance with these requirements.

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
Mandatory Reporting of Greenhouse Gases (40 CFR 98, Subpart D)	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	California Global Warming Solutions Act of 2006. This act requires the California Air Resources Board (ARB) to enact standards that will reduce GHG emissions to 1990 levels. Electricity production facilities will be regulated by the ARB.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	ARB regulations implementing mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
California Code of Regulations, tit. 20, section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2/MWh$) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lb CO_2/MWh).

GLOBAL CLIMATE CHANGE AND CALIFORNIA

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps substantially) to that change. Man-made emissions of greenhouse gases, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature finds that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Health & Safety Code, sec. 38500).

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p.5). In 2003, the Energy Commission recommended that the state require reporting of greenhouse gases or global climate change[4] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). Three years later, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (ARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such

[4] Global climate change is the result of greenhouse gases, or emissions with global warming potentials, affecting the energy balance and, thereby, climate of the planet. The terms greenhouse gases (GHG) and global climate change (GCC) gases are used interchangeably.

reductions to be achieved by 2020.[5] To achieve this, ARB has a mandate to define the 1990 emissions levels and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December 2007, and adopted a statewide scoping plan in December 2008 to identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB staff is developing regulatory language to implement its plan and holds ongoing public workshops on key elements of the recommended GHG reduction measures, including market mechanisms (ARB 2006). The regulations must be effective by January 1, 2011, and mandatory compliance commences on January 1, 2012. The mandatory reporting requirements are effective for electric generating facilities over 1 megawatt (MW) capacity, and the due date for initial reports by existing facilities this first year was June 1, 2009.

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission, were identified in the California Climate Action Team's Report to the Governor (CalEPA 2006). The scoping plan approved by the ARB in December 2008 builds upon the overall climate policies of the Climate Action Team report and shows the recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33% Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008c).

It is possible that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest effect for the least cost). For example, the ARB proposes a 40% reduction in GHG from the electricity sector, even though the sector currently only produces about 25% of the state's GHG emissions. In response, in September 2008 the Energy Commission and the California Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified points of regulation within the sector should ARB decide that a multi-sector cap and trade system is warranted.

The Energy Commission's *2007 Integrated Energy Policy Report* (IEPR) also addresses climate change within the electricity, natural gas, and transportation sectors (CEC 2007a). For the electricity sector, it recommends such approaches as pursuing all cost-effective energy efficiency measures and meeting the Governor's stated goal of a 33% Renewables Portfolio Standard.

[5] Governor Schwarzenegger has also issued Executive Order S-3-05 establishing a goal of 80% below 1990 levels by 2050.

SB 1368,[6] also enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibit California utilities from entering into long-term commitments with any base load facilities that exceed the Greenhouse Gas Emission Performance Standard of 0.500 metric tonnes CO_2 per megawatt-hour[7] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California. If a project, instate or out of state, plans to sell base load electricity to California utilities, the utilities will have to demonstrate that the project complies with the EPS. *Base load* units are defined as those designed and intended to provide electricity at an annualized plant capacity factor of at least 60%. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant and not on full load heat rates [20 CCR §2903(a)].

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap and trade market to reduce greenhouse gas emissions in the western United States and the Western Electricity Coordinating Council (WECC). The timelines for the implementation of this program are similar to those of AB 32, with full roll-out beginning in 2012. As with AB 32, the electricity sector has been a major focus of attention.

ELECTRICITY PROJECT GREENHOUSE GAS EMISSIONS

Electricity use can be as simple as turning on a switch to operate a light or fan. The system to deliver the adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to meet demand, such that the dispatch of a new source of generation unavoidably curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[8] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. In this context, and because fossil-fueled resources produce GHG emissions, it is important to consider

[6] California Code of Regulations, Title 20 § 2900 and Public Utilities Code § 8340 et seq.

[7] The Emission Performance Standard only applies to carbon dioxide and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[8] See page CEC 2009b, page 95.

the role and necessity of also adding fossil-fuel resources. A report prepared as a response to the GHG OII (CEC 2009a) defines five roles that gas-fired power plants are likely to fulfill in a high-renewables, low-GHG system (CEC 2009b, pp 93 and 94):

1. Intermittent generation support
2. Local capacity requirements
3. Grid operations support
4. Extreme load and system emergency
5. General energy support.

The Energy Commission staff-sponsored report reasonably assumes that non-renewable power plants added to the system would almost exclusively be natural gas-fueled. Nuclear, geothermal, and biomass plants are generally base load and not dispatchable. Solid fueled projects are also generally base load, not dispatchable and carbon sequestration technologies needed to reduce the GHG emission rates to meet the EPS are not yet developed (CEC 2009b, p. 92). Further, California has almost no sites available to add highly dispatchable hydroelectric generation.

Generation of electricity using any fossil fuel, including natural gas, can produce greenhouse gases with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. For fossil fuel-fired power plants, the GHG emissions include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused or recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials. Global warming potential is a relative measure, compared to carbon dioxide, of a compound’s residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO2E) metric tonnes (MT) for ease of comparison.

CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of a variety of equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. Construction of A2PP would involve 12 months of activity. The applicant provided a GHG emission estimate for the entirety of the construction phase (CH2M2009f). The GHG emissions estimate, presented below in **Greenhouse Gas Table 2**, includes the total emissions for the 12 months of construction activity in terms of CO_2-equivalent.

Greenhouse Gas Table 2
A2PP, Estimated Potential Construction Greenhouse Gas Emissions

	Construction-Phase GHG

Construction Source	Emissions (MTCO2E) [a]
Onsite construction	1,070
Deliveries to construction site	342
Worker travel to/from construction site	1,282
Construction of linear facilities	18
Deliveries to linear facilities construction areas	8
Worker travel to/from linear facilities construction areas	160
Construction Total	2,880

Source: AFC Table 5.1E-5 and Response to Data Request 7, Attachment DR7-1 (CH2M2009f, CH2M2009k).
Notes: a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms

OPERATIONS

The proposed A2PP a nominal 174-megawatt (MW) facility consisting of three General Electric (GE) Energy LM6000PG SPRINT natural gas-fired turbine generators and associated equipment. ~~While~~ TID does not intend to run A2PP as a base load facility, although TID proposes to permit A2PP to have an annual plant availability of 92 to 98%. ~~It would be possible for plant availability to exceed 98% for a given 12-month period.~~ TID identifies some basic project objectives as to provide fast-starting, load-following peaking generating units, to provide firming for intermittent renewable resources, and to allow better economic dispatch of TID's existing generation fleet (TID Comments, June 7, 2010). ~~However, the~~ The exact operational profile of this peaking plant will depend on the variable demand within and variable deliveries to TID's own Balancing Authority.

The primary sources of GHG would be the natural gas fired combustion turbines. There would also be a small amount of GHG emissions from sulfur hexafluoride (SF_6) leaking from new electrical component equipment. The employee and delivery traffic GHG emissions from off-site activities are negligible in comparison with the gas turbine GHG emissions.

Greenhouse Gas Table 3 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials. A small amount of additional SF_6 containing equipment will be required for this project, and the leakage of SF_6 and its CO_2 equivalent emissions have been estimated.

Greenhouse Gas Table 3
A2PP, Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	**Operational GHG Emissions (MTCO2E/yr)** [a]
Combustion Turbine Generators (Three CTGs)	727,633
Switchyard Breakers	38
Total Project GHG Emissions, excluding Off-Site Emissions (MTCO2E/yr)	**727,671**
Estimated Annual Energy Output (MWh/yr) [b]	1,425,217
Estimated Annualized GHG Performance (MTCO2/MWh)	**0.510**

Sources: AFC Appendix Table 5.1A-6 (TID2009a).

Notes: a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.

b. Based on maximum permitted capacity of 8,760 hours of annual operation. (TID2009a, AFC Table 5.1A-6).

The proposed project would be permitted, on an annual basis, to emit over 727,671 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. The proposed A2PP, at 0.51 MTCO2/MWh, would slightly exceed the limits of SB 1368 and the Greenhouse Gas Emission Performance Standard of 0.500 MTCO2/MWh for base load generation. However, A2PP is not designed or intended for base load generation, even though TID has requested permission to run the facility at greater than a 60% capacity factor. This simple-cycle facility is not expected to operate at greater than 33% capacity factor, and Energy Commission staff experience indicates that this type of facility is only likely to exceed 30% annual capacity factor in an emergency or crisis situation. Therefore, although the facility would be allowed to operate at greater than 60% capacity factor if needed, staff agrees with the applicant that A2PP is not designed or intended to do so.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses the cumulative effects of GHG emissions caused by both construction and operation. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Staff is continuing to monitor development of AB 32 Scoping Plan implementation efforts and general trends and developments affecting GHG regulation in the electricity sector.

The impact of GHG emissions caused by this natural gas-fired facility is characterized by considering how the power plant would affect the overall electricity system. The integrated electricity system depends on generation resources to provide energy and satisfy local capacity needs. Energy Commission staff follows the concept of a “blueprint” to describe the long-term roles of fossil-fueled power plants in California’s electricity system (CEC 2009a). The five separate roles that gas-fired power plants are most likely to fulfill in the future of a high-renewables, low-GHG system include: 1) Intermittent generation support; 2) Local capacity requirements; 3) Grid operations support; 4) Extreme load and system emergencies support; and 5) General energy support (CEC 2009b, p. 93). A2PP is analyzed here for its role in providing local capacity and generation and general energy support for expected generation retirements or replacements.

CONSTRUCTION IMPACTS

Staff does not believe that the minor GHG emission increases from construction activities would be significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends to address criteria pollutant emissions, such as limiting idling times and requiring, as appropriate, using equipment that meets the latest criteria pollutant emissions standards would further minimize greenhouse gas emissions to the extent feasible. The use of newer equipment will increase fuel efficiency and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

New, efficient, natural gas-fired generation promotes the state's efforts to improve GHG electrical generation efficiencies and, therefore, reduce the amount of natural gas used by electricity generation and greenhouse gas emissions. As the *2007 Integrated Energy Policy Report* (CEC 2007a, p. 184) noted:

> New natural gas-fueled electricity generation technologies offer efficiency, environmental, and other benefits to California, specifically by reducing the amount of natural gas used—and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants. The 2003 and 2005 IEPRs noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient power plants.

Thus, in the context of the Energy Commission's *Integrated Energy Policy Report*, the A2PP furthers the state's strategy to promote generation system efficiency and reduce fuel use and GHG emissions. As stated in the 2009 *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* (CEC 2009b, p.23):

> When one resource is added to the system, all else being held equal, another resource will generate less power. If the new resource has a lower cost or fewer emissions than the existing resource mix, the aggregate system characteristics will change to reflect the cheaper power and lower GHG emissions rate.

Net GHG emissions for the integrated electric system will decline when new gas-fired power plants are added to: 1) permit the penetration of renewable generation to the 33% target; 2) improve the overall efficiency of the electric system; or 3) serve load growth or capacity needs more efficiently than the existing fleet (CEC 2009b, p. 98).

The Role of A2PP in Local Generation Displacement

The proposed A2PP would have a net heat rate of approximately 9,835 Btu/kWh[9], which leads to an estimated GHG performance factor of approximately 0.51 MTCO2/MWh. The heat rate, energy output and GHG emissions of other local generation resources are listed in **Greenhouse Gas Table 4**. Compared to the other existing simple-cycle and peaker power plants in the TID Balancing Authority area, the proposed A2PP would be more efficient, and emit fewer GHG emissions during any hour of operation. Local generating units with the best (lowest) heat rate or lowest GHG performance factor generally operate more than other units with higher heat rates, as shown by the relative amount of energy (GWh) produced in 2008 from the local units. However, dispatch order can change, or deviate from economic or efficiency dispatch, in any one year or due to other concerns such as permit limits, contractual obligations, droughts, heat waves, local reliability needs or emergencies. These deviations, however, are likely to occur infrequently and are unplanned. The A2PP would not increase the overall system heat rate for natural gas plants because it would offer greater flexibility than the existing combined cycle Walnut Energy Center at a lower heat rate than existing peaker power plants in the area.

Greenhouse Gas Table 4
San Joaquin and Stanislaus Counties, Local Generation Heat Rates and 2008 Energy Outputs

Plant Name	Heat Rate (Btu/kWh) [a]	2008 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Lodi Energy Center (~~under agency review~~in development)	7,112	Approved ~~Potential approval~~ in 2010	0.377
Walnut Energy Center	7,822	1,578	0.415
Woodland 1	8,761	416	0.465
Tracy Combined Cycle (~~under agency review~~in development)	8,056	~~Potential approval~~ Approved in 2010	0.474
Lodi STIG	9,000	72	0.477
Almond Power Plant	11,074	62	0.587
MID Ripon	11,908	33	0.631
McClure 1, 2	15,222	18	0.807
Tracy Peaker Plant	12,310	11	0.652
Walnut Power Plant (Peaker)	19,098	1	1.013
Proposed TID A2PP (at permitted limit)	9,835	1,425 (max est.)	0.510

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER); shows the proposed TID A2PP at the permitted capacity of 8,760 hours annually although it is only expected to operate up to 5,000 hours on annualized basis (CH2M2009h).

Notes: a. Based on the Higher Heating Value or HHV of the fuel.

The proposed A2PP would not be physically within a major local reliability area like the Greater Bay Area. However, it would provide local reliability and displace other power plants within the TID Balancing Authority area, which allows TID to better use the existing Walnut Energy Center, and A2PP allows displacement of energy from the existing, less-efficient Almond and Walnut power plants (CH2M2009h).

[9] Based on the High Heating Value (HHV) of the fuel(s) used. HHV is used for all heat rate and fuel conversions to GHG mass emissions that are discussed in this document.

The Role of A2PP in the Integration of Renewable Energy

As California moves towards an increased reliance on renewable energy, the bulk of renewable generation available to, and used in California, will be intermittent wind generation with some intermittent solar (CEC 2009b, p.3). To accommodate the increased variability in generation due to increasing renewable penetration, compounded by increasing load variability, control authorities such as the California Independent System Operator (CAISO) need increased flexibility from other generation resources such as hydro generation, dispatchable pump loads, energy storage systems, and fast ramping and fast starting fossil fuel generation resources (CAISO 2007, p. 14).

A2PP would provide flexible, dispatchable and fast ramping[10] power consistent with the CAISO use of this term, and it would not obstruct penetration of renewable energy. A2PP will serve as an important firming source for intermittent renewable resources in support of TID's RPS and GHG goals (CH2M2009f). TID claims that A2PP would allow more efficient use of TID's wind resource from the Pacific Northwest and other renewable resources. In 2004, TID Board adopted its own 20% RPS standard by 2017. The wind project has brought 28% RPS to TID's profile. Therefore, TID has met its own RPS goal to date.

The proposed simple-cycle LM6000PG gas turbines for A2PP provide TID with quick starting and fast ramping power that would be much more likely to foster integration of renewable energy than comparable non-renewable base load or intermediate energy resources. TID investigated potentially using combined cycle turbines with quick-startup packages, but found them to be too large to meet TID's load increment criteria (CH2M2009f).

The amount of dispatchable fossil fuel generation will have to be significantly increased to meet the statewide 20% RPS (CAISO 2007, p.113); the 33% RPS will require even more dispatchable resources to integrate the renewables. However, this does not suggest the existing and new fossil fuel capacity will operate more. **Greenhouse Gas Table 5** shows how the build-out of either the 20% or the 33% statewide RPS goal will affect generation from new and existing non-renewable resources. Should California reach its goal of meeting 33%of its retail demand in 2020 with renewable energy, non-renewable, most likely fossil-fueled, energy needs will fall by over 36,000 GWh/year. In other words, all growth will need to come from renewable resources to achieve the 33% RPS. And some existing and new fossil units will generate less energy than they currently do, given the expected growth in retail sales.

These assumptions are conservative in that the forecasted growth in retail sales assumes that the impacts of planned increases in expenditures on (uncommitted) energy efficiency are already embodied in the retail sales forecast.[11] Energy Commission staff estimates that as much as 18,000 GWh of additional savings due to

[10] The CAISO categorizes *fast-ramping* as a generator capable of going from lowest power to highest in under 20 minutes, or greater than 10 MW per minute.

[11] Energy efficiency savings are already represented in the current Energy Commission demand forecast adopted December 2009 (CEC2009c).

uncommitted energy efficiency programs may be forthcoming.[12] This would reduce non-renewable energy needs by a further 12,000 GWh given a 33% RPS.

Greenhouse Gas Table 5
Estimated Changes in Non-Renewable Energy Potentially Needed to Meet California Loads, 2008 to 2020

California Electricity Supply	**Annual GWh**	
Statewide Retail Sales, 2008, actual [a]	264,794	
Statewide Retail Sales, 2020, forecast [a]	289,697	
Growth in Retail Sales, 2008-20	24,903	
Growth in Net Energy for Load, 2008-20 [b]	29,840	
California Renewable Electricity	**GWh @ 20% RPS**	**GWh @ 33% RPS**
Renewable Energy Requirements, 2020 [c]	57,939	95,600
Current Renewable Energy, 2008	29,174	
Change in Renewable Energy, 2008-20 [c]	28,765	66,426
Resulting Change in Non-Renewable Energy	176	-36,586

Source: Energy Commission staff 2010.
Notes:
a. 2009 IEPR Demand Forecast, Form 1.1c. Excludes pumping loads for entities that do not have an RPS.
b. 2009 IEPR Demand Forecast, Form 1.5a.
c. RPS requirements are a percentage of retail sales.

The Role of A2PP in Retirements/Replacements

A2PP would be permitted to run continuously and provide more than 1,400 GWh of natural gas-fired generation that could replace resources that are or will likely be precluded from serving California loads. State policies, including GHG goals, are discouraging or prohibiting new contracts and new investments in coal-fired generation, generation that relies on water for once-through cooling, and aging power plants (CEC 2007a). Some of the existing plants that are likely to require significant capital investments to continue operation in light of these policies may be unlikely to undertake the investments and will retire or be replaced.

Replacement of Coal-Fired Generation

Coal-fired resources are effectively prohibited from entering into new long-term, base load contracts for California deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, more than 18,000 GWh of energy procured by California utilities under existing contracts will have to be replaced; these contracts are listed in **Greenhouse Gas Table 6**.

This represents almost half of the energy associated with California utility contracts with coal-fired resources that will expire by 2030. If the State enacts a carbon adder[13], all the coal contracts (including those in **Greenhouse Gas Table 6**, which expire by 2020, and

[12] See *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast* (CEC-200-2010-001-D, January, 2010), page 2. Table 1 indicates that additional conservation for the three investor-owned utilities may be as high as 14,374 GWh. Increasing this value by 25% to account for the state's publicly-owned utilities yields a total reduction of 17,967 GWh.

[13] A carbon adder or carbon tax is a specific value added to the cost of a project per ton of associated carbon or carbon dioxide emissions. Because it is based on, but not limited to, actual operations and emission and can be trued up at year end, it is considered a simple mechanism to assign environmental costs to a project.

other contracts that expire beyond 2020 and are not shown in the table) may be retired at an accelerated rate as coal-fired energy becomes uncompetitive. Also shown are the approximate 500 MW of in-state coal and petroleum coke-fired capacity that may not be able to secure long term contracts with California utilities due to the SB 1368 Emission Performance Standard. As these contracts expire, new and existing generation resources will replace the lost energy and capacity. Some will come from renewable generation; some will come from new and existing natural gas fired generation. New generation resources generally will emit significantly less GHG than the coal and petroleum coke-fired generation, which average about 1.0 MTCO2/MWh, or two times more than the proposed A2PP, resulting in a significant net reduction in GHG emissions from the California electricity sector.

Greenhouse Gas Table 6
Expiring Long-term Contracts with Coal-fired Generation 2009 – 2020

Utility	**Facility** [a]	**Contract Expiration**	**Annual GWh Delivered to CA**
PG&E, SCE	Misc In-state Qual. Facilities [a]	2009-2019	4,086
LADWP	Intermountain	2009-2013	3,163 [b]
City of Riverside	Bonanza, Hunter	2010	385
Department of Water Resources	Reid Gardner	2013 [c]	1,211
SDG&E	Boardman	2013	555
SCE	Four Corners	2016	4,920
Turlock Irrigation District	Boardman	2018	370
LADWP	Navajo	2019	3,832
		TOTAL	**18,522**

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.

Notes: a. All facilities are located out-of-state except for the Miscellaneous In-state Qualifying Facilities.

b. Estimated annual reduction in energy provided to LADWP by Utah utilities from their entitlement by 2013.

c. Contract not subject to Emissions Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.

Retirement of Generation Using Once-Through Cooling

New, dispatchable resources like A2PP would also be required to provide generation capacity (that is, the ability to meet fluctuating, intermittent electricity loads) in the likely event that facilities utilizing once-through cooling (OTC) are retired. The State Water Resource Control Board (SWRCB) has proposed significant changes to OTC units, which would likely require retrofit, retirement, or significant curtailment of dozens of generating units. In 2008, these units collectively produced about 58,000 GWh. While those OTC facilities owned and operated by utilities and recently-built combined cycle plants may well install dry or wet cooling towers, it is unlikely that the aging, merchant plants will do so. Most of these units operate at low capacity factors, suggesting a limited ability to compete in the current electricity market. Although the timing would be uncertain, new resources would out-compete aging plants and would likely displace the energy provided by OTC facilities and accelerate the retirements.

Any additional costs associated with complying with the SWRCB regulation would be amortized over a limited revenue stream today and into the foreseeable future. Their energy and much of their dispatchable, load-following capability will have to be replaced. These units constitute over 15,000 MW of merchant capacity and 17,800 GWh of merchant energy. Of this, much but not all of the capacity and energy are in local reliability areas, requiring a large share of replacement capacity – absent transmission upgrades – to locations in the same local reliability area. **Greenhouse Gas Table 7** provides a summary of the utility and merchant energy supplies affected by the OTC regulations.

Greenhouse Gas Table 7
Units Utilizing Once-Through Cooling: Capacity and 2008 Energy Output [a]

Plant, Unit Name	Owner	Local Reliability Area	Aging Plant?	Capacity (MW)	2008 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Diablo Canyon 1, 2	Utility	None	No	2,232	17,091	Nuclear
San Onofre 2, 3	Utility	L.A. Basin	No	2,246	15,392	Nuclear
Broadway 3 [b]	Utility	L.A. Basin	Yes	75	90	0.648
El Centro 3, 4 [b]	Utility	None	Yes	132	238	0.814
Grayson 3-5 [b]	Utility	LADWP	Yes	108	150	0.799
Grayson CC [b]	Utility	LADWP	Yes	130	27	0.896
Harbor CC	Utility	LADWP	No	227	203	0.509
Haynes 1, 2, 5, 6	Utility	LADWP	Yes	1,046	1,529	0.578
Haynes CC [c]	Utility	LADWP	No	560	3,423	0.376
Humboldt Bay 1, 2 [a]	Utility	Humboldt	Yes	107	507	0.683
Olive 1, 2 [b]	Utility	LADWP	Yes	110	11	1.008
Scattergood 1-3	Utility	LADWP	Yes	803	1,327	0.618
Utility-Owned				**7,776**	**39,988**	**0.693**
Alamitos 1 - 6	Merchant	L.A. Basin	Yes	1,970	2,533	0.661
Contra Costa 6, 7	Merchant	S.F. Bay Area	Yes	680	160	0.615
Coolwater 1-4 [b]	Merchant	None	Yes	727	576	0.633
El Segundo 3, 4	Merchant	L.A. Basin	Yes	670	508	0.576
Encina 1-5	Merchant	San Diego	Yes	951	997	0.674
Etiwanda 3, 4 [b]	Merchant	L.A. Basin	Yes	666	848	0.631
Huntington Beach 1, 2	Merchant	L.A. Basin	Yes	430	916	0.591
Huntington Beach 3, 4	Merchant	L.A. Basin	No	450	620	0.563
Mandalay 1, 2	Merchant	Ventura	Yes	436	597	0.528
Morro Bay 3, 4	Merchant	None	Yes	600	83	0.524
Moss Landing 6, 7	Merchant	None	Yes	1,404	1,375	0.661
Moss Landing 1, 2	Merchant	None	No	1,080	5,791	0.378
Ormond Beach 1, 2	Merchant	Ventura	Yes	1,612	783	0.573
Pittsburg 5-7	Merchant	S.F. Bay Area	Yes	1,332	180	0.673
Potrero 3	Merchant	S.F. Bay Area	Yes	207	530	0.587
Redondo Beach 5-8	Merchant	L.A. Basin	Yes	1,343	317	0.810
South Bay 1-4	Merchant	San Diego	Yes	696	1,015	0.611
Merchant-Owned				**15,254**	**17,828**	**0.605**
Total In-State OTC				**23,030**	**57,817**	

Source; Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings
Notes:

a. OTC Humboldt Bay Units 1 and 2 are included in this list. They must retire in 2010 when the new Humboldt Bay Generating Station (not ocean-cooled), currently under construction, enters commercial operation.
b. Units are aging but are not OTC.
c. The Los Angeles Department of Water and Power (LADWP) reported a 2007 aggregate energy number of 4,003 GWh for all the

Haynes units. Staff allocated the energy between the units based on Haynes' current and historical output allocations in the LADWP fillings for 2009 IEPR.

New generation resources that can either provide local support or energy will emit significantly less GHGs than the OTC fleet. Existing aging and OTC natural gas generation average 0.6 to 0.7 MTCO2/MWh, or more than 20% higher emissions than the proposed A2PP. When project provides energy and capacity, depending on its location, it can provide a significant net reduction in GHG emissions from the electricity sector. A project located in a load pocket, for example, the Greater Bay Area Local Capacity Area, would more likely provide local reliability support as well as facilitate the retirement of aging and/or OTC power plants to a degree that the A2PP project could not.

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or...compound or increase other environmental impacts" (CEQA Guidelines § 15355). "A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts" (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This entire assessment is a cumulative impact assessment. The project would emit greenhouse gases and, therefore, has been analyzed as a potential cumulative impact in the context of its effect on the electricity system, resulting GHG emissions from the system, and existing GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Ultimately, ARB's AB 32 regulations are likely to address both the degree of electricity generation sector emissions reductions (through cap-and-trade), and the method by which those reductions will be achieved (e.g., through command-and-control). However, the exact approach to be taken is currently under development. That regulatory approach may address emissions not only from the newer, more efficient, and lower emitting facilities licensed by the Energy Commission, but also from the older, higher-emitting facilities not subject to any GHG reduction standard that this agency could presently impose. This programmatic approach is likely to be more effective in reducing GHG emissions overall from the electricity sector than one that merely relies on displacing out-of-state coal plants ("leakage") or older "dirtier" facilities.

The Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified the regulation points should ARB decide that a multi-sector cap-and-trade system is warranted. As ARB codifies accurate GHG inventories and methods, it may become apparent that emission reductions from the generation sector are less cost-effective than other sectors, and that other sectors of sources can achieve reductions with relative ease and cost-effectiveness.

The project would be subject to ARB's mandatory reporting requirements and potentially other future requirements mandating compliance with AB 32 that are being developed by ARB. How the project would comply with these ARB requirements is speculative at this time, but compliance would be mandatory. The ARB's mandatory GHG emissions reporting requirements do not indicate whether the project, as defined, would comply with the potential GHG emissions reduction regulations being formulated under AB 32. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB. Similarly, this project would be subject to federal mandatory reporting of GHG.

Reporting of GHG emissions would enable the project to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide the information to demonstrate compliance with any applicable EPS that could be enacted in the next few years. The A2PP would exceed the Emission Performance Standard in SB 1368 for base load generation, but as a simple-cycle power plant A2PP is not designed or intended for base load generation. Therefore, the SB 1368 limitation does not apply to this facility.

The Energy Commission established a precedent decision in the Final Commission Decision for the Avenal Energy Project. This decision requires all new natural gas fired power plants certified by the Energy Commission to: (a) not increase the overall system heat rate for natural gas plants, (b) not interfere with generation from existing renewable facilities nor interfere with the integration of new renewable generation, and (c) take into account these factors to ensure a reduction of system-wide GHG emissions and support the goals and policies of AB 32 (CEC 2009e). The A2PP, with its low heat rate and high flexibility, and rapid start and fast ramping capabilities would satisfy these conditions.

NOTEWORTHY PUBLIC BENEFITS

Electricity is produced by operation of inter-connected generation resources and, by knowing the fuel used by the generation sector, the resulting GHG emissions can be known. The operation of A2PP would affect the overall electricity system operation and GHG emissions in several ways:

- A2PP would provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.
- A2PP would operate at a low heat rate to displace some less efficient and less flexible local generation in the dispatch order of gas-fired facilities that are required to provide electricity reliability in the TID system.
- A2PP would facilitate to some degree the replacement of out-of-state coal electricity generation that must be phased out in conformance with the State's new Emissions Performance Standard.
- A2PP could facilitate to some extent the replacement of generation provided by aging power plants that use once-through cooling.

The project would likely lead to a net reduction in GHG emissions across the electricity system providing energy and capacity to California. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from the state's power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant. Moreover, it would be consistent with AB 32 goals.

The energy displaced by the proposed A2PP would result in a reduction in GHG emissions from the electricity system compared to other peaking generation. In other system roles, as described in **Greenhouse Gas Table 8**, the proposed A2PP would be able to minimize its GHG impacts by filling most of the expected future roles for gas-fired generation, in a high-renewables, low-GHG system.

Greenhouse Gas Table 8
A2PP, Summary of Role in Providing Energy and Capacity Resources

Services Provided by Generating Resources	Discussion, A2PP
Integration of Renewable Energy	• Would provide fast startup capability (within 2 hours). • Would provide rapid ramping capability. • Would have ability to provide regulation and reserves, and energy when renewable resources are unavailable.
Local Generation Displacement	• Would be able to satisfy/partially satisfy local capacity area (LCA) resource requirements. • Would provide voltage support. • *Would not* provide black start capability.
Ancillary Services, Grid System, and Emergency Support	• Would provide fast start-up capability (within 2 hours). • Would have low minimum load levels. • Would provide rapid ramping capability. • Would have ability to provide regulation and reserves. • *Would not* provide black start capability.
General Energy Support	• Would provide general energy support. • Could facilitate some retirements and replacements • Would provide cost-competitive energy. • Would be able to help a load-serving entity (LSE) meet resource adequacy (RA) requirements.

Source: Energy Commission staff; based on: Expected Roles for Gas-Fired Generation (CEC2009b, p. 7).

CONCLUSIONS

A2PP would be an efficient, new, dispatchable natural gas-fired simple-cycle power plant that would cause GHG emissions while generating electricity for California consumers. AB 32 emphasizes that GHG emission reductions must be "big picture" reductions that do not lead to "leakage" of such reductions to other states or countries. The project's GHG emissions per MWh would be lower than those of other peaking generation that the project would displace and, thus, would contribute to continued improvement of the California and overall Western Electricity Coordinating Council system's GHG emissions and GHG emission rate average.

The project would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from the state's power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant.

Staff notes that mandatory reporting of GHG emissions per Air Resources Board greenhouse gas regulations would occur, and this would enable the ARB to gather the information needed to regulate the A2PP in trading markets if required by the regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). The project may be subject to additional reporting requirements and GHG reduction or trading requirements as these regulations are more fully developed and implemented by ARB and U.S. EPA.

Staff does not believe that the minor GHG emission increases from construction activities would be significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures, or best practices, that staff recommends for minimizing criteria pollutants, such as limiting construction vehicle idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize greenhouse gas emissions since staff believes that the use of newer equipment would increase fuel efficiency and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. For all these reasons, staff concludes that the short-term emission of greenhouse gases during construction would be substantially reduced and would, therefore, not be significant.

The A2PP would exceed the Emission Performance Standard in SB 1368 for base load generation, but as a simple-cycle power plant, A2PP is not designed or intended for base load generation. Therefore, the SB 1368 requirements do not apply to A2PP.

<u>The A2PP would be consistent with the precedent decision regarding GHG emissions established by the Avenal Energy Project's Final Commission Decision (CEC 2009e).</u>

PROPOSED CONDITIONS OF CERTIFICATION

None proposed. The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, section 95100 et. seq.) and/or future GHG regulations formulated by the ARB and U.S. EPA, such as limits set by GHG emissions cap and trade markets.

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SOIL & WATER RESOURCES

Testimony of Vince Geronimo, PE and Rachel Cancienne, EIT

SUMMARY OF CONCLUSIONS

This section of the Staff Assessment (SA) analyzes the potential effects on soil and water resources that would occur by construction and operation of the proposed Turlock Irrigation District's (TID) Almond 2 Power Plant (A2PP) project. Based on its assessment of the proposed A2PP Project, staff concludes the following:

- Implementation of Best Management Practices (BMPs) during A2PP construction and operation in accordance with effective Storm Water Pollution Prevention Plans (SWPPP) and a Drainage, Erosion and Sedimentation Control Plan (DESCP) would avoid significant adverse effects that could be caused by transport of sediments or contaminants from the A2PP site and associated linear facilities by wind or water erosion.
- The proposed reclaimed water supply for the project would not cause a significant adverse environmental impact ~~on~~ to current or future users of the water supply.
- ~~The Waste Discharge Requirements for the City of Ceres Wastewater Treatment Plant may be revised by the Central Valley Regional Water Quality Control Board during the life of the project, which could affect both the water supply and wastewater disposal for the A2PP site.~~
- The proposed project would be constructed to comply with 100-year flood requirements and would not exacerbate flood conditions in the vicinity of the project.
- ~~The proposed project would comply with all applicable federal, state, and local laws, ordinances, regulations and standards with the adoption of the recommended conditions of certification.~~
- A2PP would not result in any unmitigated project-specific or cumulative significant adverse impacts to soil or water resources with adoption of the conditions of certification.
- The project complies with the state water policies by using reclaimed water.

Staff concludes that A2PP would not result in any unmitigated project-specific or cumulative significant adverse impacts to soil or water resources and would comply with all applicable laws, ordinances, regulations and standards (LORS) if all of the recommended conditions of certification are adopted by the Commission and implemented by TID.

INTRODUCTION

This section of the Assessment (SA) analyzes the potential effects on soil and water resources by the proposed TID Almond 2 Power Plant (A2PP). This analysis specifically focuses on the potential for A2PP to:

- cause accelerated wind or water erosion and sedimentation;
- exacerbate flood conditions in the vicinity of the project;
- adversely affect surface or groundwater supplies;
- degrade surface or groundwater quality; and
- comply with all applicable ~~laws, ordinances, regulations and standards (~~LORS~~)~~ and State policies.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

Soil and Water Resources Table 1
Laws, Ordinances, Regulations, and Standards (LORS) and Policies

Federal	
Clean Water Act/Water Pollution Control Act. P.L. 92- 500, 1972; amended by Water Quality Act of 1987, P.L. 100-4 (33 USC 466 et seq.); NPDES (CWA, Section 402)	The CWA requires states to set standards to protect, maintain, and restore water quality through the regulation of point source and certain non-point source discharges to surface water. This includes regulation of storm water discharges during construction and operation of a facility normally addressed through a general National Pollutant Discharge Elimination System (NPDES) permit.
Natural Resources Conservation Service (NRCS), National Engineering Handbook, Sections 2 and 3 (1983)	Sections 2 and 3 of the USDA-NRCS National Engineering Handbook (1983) provide standards for soil conservation and erosion prevention during construction activity.
State	
California Constitution, Article X, Section 2	The State Constitution requires that the water resources of the state be put to beneficial use to the fullest extent possible and states that the waste, unreasonable use or unreasonable method of use of water is prohibited.
Porter Cologne Water Quality Control Act (PCWQCA) (Water Code §13000 et seq.)	PCWQCA requires the State Water Resources Control Board (SWRCB) and the nine RWQCBs to adopt water quality criteria to protect state waters. These standards are typically applied to the proposed project through the Waste Discharge Requirements (WDR) permit. These regulations require that the RWQCB issue Waste Discharge Requirements specifying conditions regarding the construction, operation, monitoring and closure of waste disposal sites, including injection wells and evaporation ponds for waste disposal. WDRs are updated periodically to reflect changing technology standards and conditions.
SWRCB Res. 2009-0011 (Recycled Water Policy)	This policy supports and promotes the use of recycled water as a means to achieve sustainable local water supplies and reduction of greenhouse gases. This policy encourages the beneficial use of recycled water over disposal of recycled water. This policy states the following recycled water use goals: • “Increase the use of recycled water over 2002 levels by at least one million acre-feet per year (AF/y) by 2020 and by at least two million AF/y by 2030; • Increase the use of stormwater over use in 2007 by at least 500,000 AF/y by 2020 and by at least one million AF/y by 2030; • Increase the amount of water conserved in urban and industrial uses by comparison to 2007 by at least 20% by 2020; and Included in these goals is the substitution of as much recycled water for potable water as possible by 2030.”

SWRCB Resolution 75-58	The SWRCB has adopted policies that provide guidelines for water quality protection. The principal policy of the SWRCB that specifically addresses the siting of energy facilities is the Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling (adopted by the Board on June 19, 1975 as Resolution 75-58). This policy states that fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. This SWRCB policy requires that power plant cooling water should come from, in order of priority: wastewater being discharged to the ocean, ocean water, brackish water from natural sources or irrigation return flow, inland waste waters of low total dissolved solids, and other inland waters. This policy also includes cooling water discharge prohibitions such as land application.
California Water Code (CWC) Section 461	CWC Section 461 addresses the conservation of all available water resources and requires the maximum reuse of reclaimed water in satisfaction of the requirements for beneficial uses of water.
California Water Code (CWC) Section 13550	CWC Section 13550 requires the use of reclaimed water for industrial purposes subject to reclaimed water being available and meeting certain conditions such as the quality and quantity of the reclaimed water are suitable for the use, the cost is reasonable, and the use is not detrimental to public health.
California Water Code (CWC) Section 13551	CWC Section 13551 limits the use of water with quality suitable for potable domestic use for nonpotable uses if suitable recycled water is available.
California Water Code (CWC) Section 13751	CWC Section 13751 mandates that within 60 days of construction, alteration, abandonment or destruction of a groundwater well a completion report be filed to the appropriate water agency.
Recycling Act of 1991 (Water Code § 13575 et esq.)	The Water Recycling Act of 1991 encourages the use of recycled water for certain uses and establishes standards for the development and implementation of recycled water programs.
California Health and Safety Code, Division 104, Part 12, Chapter 4 (California Safe Drinking Water Act)	The California Safe Drinking Water Act requires public water systems to obtain a Domestic Water Supply Permit. Public water systems are defined as a system for the provision of water for human consumption through pipes or other constructed conveyances that has 15 or more service connections or regularly serves at least 25 individuals daily at least 60 days out the year. California Department of Public Health (CDPH) administers the Domestic Water Supply Permit program. The proposed project would likely be considered a non-transient, non-community water system.
Local	
Stanislaus County General Plan; Chapter 7, Agricultural Element	Provides limits for development of agricultural soils.
Stanislaus County Code; Title 13, Streets, Sidewalks, and Public Places	Provides requirements for construction of underground utilities along County roads.
Stanislaus County Code; Title 16, Buildings and Construction	Provides the Building Code for Stanislaus County, including general design standards and an amendment to the California Building Code for grading.
Stanislaus County Code; Title 21, Zoning	Provides information on zoning and outlines the accepted uses for lands under a Williamson Contract.
Stanislaus County Standards and Specifications	Provides the County's minimum requirements for excavation safety, dust controls, earthwork, erosion and pollution prevention, and more.
Stanislaus County Storm Water Management Plan	Regulates Best Management Practices (BMPs) for construction activities.
City of Ceres Municipal Code	Provides requirements for development of land within the City limits and requirements for obtaining permits for water wells. Provides grading requirements and permit information, preliminary soil report requirements, regulates BMPs for construction activities, and gives general design standards.

City of Ceres General Plan; Chapters 4 (Public Utilities and Services) and 6 (Agricultural and Natural Resources)	Policies for water supply and delivery; wastewater collection, treatment, and disposal; stormwater drainage; and water resources.
City of Ceres Improvement Standards	Provides the City's minimum requirements for earthwork and construction activities.

REGIONAL SETTING

REGIONAL WATER RESOURCES

Surface Waters

The proposed project site is located within the lower San Joaquin Valley in Stanislaus County in the City of Ceres, California, between the Merced River and Tuolumne River along Hwy 99. Major surface water bodies in Stanislaus County include the Stanislaus and Tuolumne Rivers which terminate in the San Joaquin River west of project site. The project site is approximately 3 miles south of the Tuolumne River and approximately eight miles to the east of the San Joaquin River.

The Central Valley Regional Water Quality Control Board (RWQCB) implements water quality regulations in the Ceres area, which include: setting water quality standards, issuing waste discharge requirements, determining compliance with those requirements, and taking appropriate enforcement actions. Each RWQCB adopts a water quality control plan, or Basin Plan, which establishes water quality objectives to ensure the reasonable protection of beneficial uses and a program of implementation for achieving water quality objectives within their basin. Water quality objectives for the Tuolumne and San Joaquin rivers are contained in the Water Quality Control Plan for the Sacramento River and San Joaquin River Basins (Basin Plan) (CVRWQCB1998). The lower Tuolumne River between Don Pedro Reservoir and the San Joaquin River, as well as the San Joaquin River between the Merced and Tuolumne tributaries are considered impaired water bodies per the Basin Plan. ~~Ceres, CA is located between the Merced River and Tuolumne River along Hwy 99.~~

Climate

Average annual rainfall is about 12 inches in the City of Modesto, just north of the project site. Most of the precipitation occurs between November and April, while the summer months are virtually rainless. **Soil and Water Resources Table 2** provides average historical rainfall from the meteorological station in Modesto.

Soil and Water Resources Table 2
Average Rainfall near the Proposed Project Site (1906-2007)

Precipitation	Annual	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Average	12.20	0.62	1.24	2.06	2.47	2.06	1.93	1.02	0.45	0.12	0.02	0.04	0.17

Source: WRRC2009

Groundwater

The A2PP project site is located within the Turlock Subbasin of the San Joaquin Valley Groundwater Basin. The Turlock Subbasin lies between the Tuolumne and Merced

Rivers and is bounded on the west by the San Joaquin River and on the east by the basement rock of the Sierra Nevada foothills. The subbasin shares its northern, western, and southern boundaries with the Modesto, Delta-Mendota, and Merced Groundwater Subbasins, respectively. Groundwater in the Turlock Subbasin flows primarily to the southwest following the regional dip of basement rock and sedimentary units towards the San Joaquin River (DWR2006).

Groundwater levels in the Turlock Subbasin have steadily declined over time, with a steep decline of approximately 15 feet between 1970 and 1992. The primary hydrogeologic units in the Turlock Subbasin include both consolidated and unconsolidated sedimentary deposits. Well yields in the Turlock Subbasin range from 200 to 4,500 gallons per minute (gpm), with an average yield of 1,000 to 2,000 ~~gallons per minute~~ gpm. Well depths in the subbasin range from 50 to 350 feet below ground surface (bgs) (DWR2006).

Groundwater in the Turlock Subbasin is of the sodium-calcium bicarbonate type and has total dissolved solids values ranging from 100 to 930 milligrams per liter (mg/L) throughout the subbasin. There are localized areas of hard groundwater, nitrate, chloride, boron, and dibromochloropropane (DBCP); however, unless otherwise designated by the Central Valley RWQCB, all ground waters are considered suitable for municipal and domestic water supply, agricultural supply, and industrial service and process supply (DWR2006).

PROJECT, SITE, AND VICINITY DESCRIPTION

The proposed A2PP would be a natural gas-fired, simple-cycle peaking facility rated at a gross generating capacity of 174 megawatts (MW). The project site is a 4.6-acre parcel near Ceres, California. The site is located on land owned by TID and is adjacent to the existing TID Almond Power Plant (APP) to the south.~~ A2PP would be operated in tandem with the existing APP.~~ Based on the applicant's AFC, oral responses to questions asked during the public workshop held on Sept. 22, 2009, and written Data Responses, staff believes that all existing facilities in APP that would be shared between sites, discussed herein, are adequate for the A2PP expansion. A WinCo distribution warehouse is located ~~sits~~ to the west, a farm supply facility to the north, and a modular building distributor and drilling equipment storage facility to the east. In addition to the A2PP site, the project includes an approximately ~~1.85~~ <u>6.4</u>-acre laydown and parking area to the ~~north~~ <u>west</u> of the project site. The project includes a new 11.6-mile long natural gas pipeline, two transmission corridors (0.9 and 1.2 miles long with 0.0066 and 0.0092 acre, respectively, required for pole footprints), and the ~~reconductoring~~ <u>re-rating</u> of an existing 69-kV transmission line (TID2009a and CH2MHILL2009k).

<u>Water Supply during Construction</u>

During construction, workers would utilize the existing fire system on the APP site, which is supplied via groundwater from the well on the APP site~~,~~ or would pump and truck fresh water to the A2PP site from the TID irrigation canal to the south. Construction of the A2PP project is scheduled to last 12 months. The entire project site, approximately 4.6 acres, would be graded during construction. Construction water would be required primarily for dust suppression. The average daily water use for construction would be 36,000 gallons per day (gpd) and daily maximum water use would be 144,000 ~~gallons per day~~ gpd. The average water use for the 12-month construction period would be 13.14 million gallons (40.3 acre feet (AF)); maximum would be 52.56 million gallons (161.3 AF).

Project Water Supply

Project water use would be for combustion turbine air inlet evaporative cooling, SPRay INTer-cooling water injection (SPRINT feature of the LM6000 Sprint) for power augmentation, combustion turbine water injection for control of oxides of nitrogen, and turbine washing. A2PP process water would be supplied to the site via the existing water delivery system used for APP. Water for APP is pumped from approximately 35 to 65 feet ~~below ground surface~~ bgs near the City of Ceres Waste Water Treatment Plant (WWTP) percolation-evaporation (P-E) basins. Water is delivered to the power plant site via a 6-inch diameter pipeline between the APP and the City of Ceres WWTP. A2PP's average daily water use would be approximately 459,360 ~~gallons of water per day (~~gpd~~)~~ assuming 60ºF (see **Soil and Water Resources Table 3**). The power plant would use about 293 ~~acre-feet~~ AF of process water per year assuming typical expected operation of 5,000 hours per year (57% capacity factor) and average daily temperatures. The case for operating 8,760 hours per year (100% capacity factor) was also evaluated by the applicant. Total water use for this case would be approximately 514 acre-feet per year (AFY), assuming average daily temperatures. When ambient temperatures increase to 110ºF, the expected daily water use increases to 502,560 gpd, which would increase projected annual use values. Staff estimates that the annual increase ~~c~~would not be greater than 50 AFY because the maximum daily use (with a heat balance case of 110^{o}F) equates to approximately 563 AFY.

Soil and Water Resources Table 3
Estimated Maximum and Average Annual Water Use for A2PP Operations

Process and Cooling Water Use Annual Hours of Operation	Projected Annual Use	
	At 60^{o}F (ac-ft)	At 110^{o}F (ac-ft)
2,917 hours per year (33% Capacity)		188
5,000 hours per year	293	

Source: TID2009a

The estimate of 514 AFY would be an upper bound estimate of water use ~~since~~ because it is unlikely the project would be operated at 100% capacity. As discussed in the Air Quality section, staff agrees with the applicant that although the facility would be allowed to operate at greater than 60% capacity factor if needed, A2PP is not designed or intended to do so. This simple-cycle facility is not expected to operate at greater than 33% capacity factor, and ~~Energy Commission~~ staff's experience indicates that this type of facility is only likely to exceed 30% annual capacity factor in an emergency or crisis situation.

Groundwater

The City of Ceres relies on groundwater as its municipal water supply (Ceres1997). The city maintains ten wells, eight of which are active (TID2009a). One of the city's municipal wells is located adjacent to the Ceres WWTP. TID pumps approximately

16,000 gallons per day (gpd) of groundwater from their existing well on the APP site. The groundwater is used for sanitary service water for the APP. A2PP would rely on the existing APP groundwater well, owned and operated by TID, for sanitary service water.

The TID ~~owns~~ wells are in the vicinity of the Ceres WWTP. The Ceres WWTP pumps groundwater, via TID-owned wells, to maintain the groundwater levels below the crop root zone (about 6 to 10 feet below ground surface). Groundwater extraction is necessary to lower the local shallow groundwater table and improve percolation at the Ceres WWTP. The extracted water is piped to concrete-lined laterals within the TID network for use by other areas in the district.

The Ceres WWTP is located about one-half mile ~~feet~~ from APP/A2PP. APP currently pumps groundwater extracted near the Ceres WWTP Percolation-Evaporation (P-E) basins for industrial use. The groundwater is best described as reclaimed wastewater infiltrated through the P-E basins, which. The reclaimed wastewater comes primarily from sanitary wastewater (TID2009a). The wastewater receives primary treatment and is before discharged to the Ceres WWTP P-E basins. **Soil and Water Resources Table 4** shows typical concentrations of select harmful constituents in discharge waters of Ceres WWTP (TID2009a). As the wastewater percolates into the ground, the soil acts as a filter for organic material, microorganisms, and nutrients such as nitrogen and phosphorus. The soil-filtered wastewater is pumped via the existing collection well and delivered to APP. A2PP will utilize the same 6" pipeline to deliver process water to the proposed project. The extraction well might also draw as much as 5% of the total water it obtains from adjacent groundwater sources with unknown water quality (CH2MHILL2009g). Prior to use as process and cooling water, the extracted intake water ~~would be~~ is filtered through the existing APP reverse osmosis system.

Soil and Water Resources Table 4
Select A2PP Water Quality Constituents

Parameter	Units	Extraction Well Intake[a]	Wastewater Discharge (Peak Flow)[b]	Wastewater Discharge (Average Flow)[c]
Total Dissolved Solids	mg/L	833	2714.6	2380.4
Total Alkalinity ($CaCO_3$)	mg/L	256	822.1	720.8
Nitrate (NO_3)	mg/L	3.6	11.5	10.1
Sodium	mg/L	162	519.8	455.8

[a] Ceres WWTP water quality data
[b] Expected A2PP discharge at 100°F dry bulb temperature
[c] Expected A2PP discharge at 60°F dry bulb temperature
Source: TID2009a

Wastewater Collection, Treatment, Discharge and Disposal

A2PP general plant wastewater from containment area washdown, sample drains, and facility equipment drains, as well as non-reclaimable process wastewater, would be combined with the APP effluent and conveyed to the Ceres WWTP via the existing 6-inch-diameter pipeline from the APP to the Ceres WWTP P-E basins. The wastewater from APP is currently not treated by the Ceres WWTP prior to discharge to the P-E basins. No additional treatment is expected as a result of the increased effluent from

A2PP. **Soil and Water Resources Table 4** shows expected concentrations of select contaminants in the A2PP discharge stream under peak and average flows, which are dependent on ambient temperature.

Drains that could potentially contain oil or grease would first be routed through an oil-water separator and hazardous wastewater would be hauled offsite for appropriate disposal. A2PP would utilize the existing onsite septic tank and leach field at APP to manage sanitary wastewater.

Stormwater Runoff and Drainage

The existing APP stormwater system incorporates a series of inlets and drainage pipes that discharge to an onsite retention pond, which is currently situated on the proposed location of A2PP. This existing stormwater system would be resized and relocated to the north to accommodate the A2PP. The stormwater system for the A2PP would include a series of inlets and storm drain pipes that convey rainfall runoff to the new retention pond. The retention pond would be sized for 2.41 ~~acre-feet~~ AF capacity to accommodate the 100-year runoff volume with 2.65 feet of freeboard (CH2MHILL2009f). Areas of potential oil contamination would use secondary containments that prevent the potential contaminants from entering the stormwater collection system. Drainage from these areas would be contained separate from the stormwater collection system, treated and disposed of offsite.

Soil Resources

In general, soils at the proposed A2PP project site are medium to coarse grained and range between sandy loam and loam sand in texture (USDA-NRCS2008). However, the northern three-quarters of the project site was formerly a borrow area used during the development of the adjacent WinCo facility and, due to the developed, industrial nature of the site, soil conditions could vary significantly from those shown in the NRCS soil survey. Additionally, the southern quarter of the project site is currently used as the retention pond for the existing Almond Power Plant. The pond would be filled to ground level at the beginning of construction with imported soils.

The industrial nature of the site suggests that there has been significant mixing of local soils and that imported construction fill soils have been used beneath foundations and roadways. These imported soils would have to be suitable for engineered structures and roadways, and would be expected to consist of well-graded materials. Imported soils previously used to fill the borrow pit as well as the non-native soil material used to fill the retention basin would not be expected to contain materials that are unsuitable for engineering purposes, such as organic debris or expansive clays.

The proposed A2PP is on land zoned for industrial use. Surrounding land uses include industrial, municipal, residential, and agricultural uses. Proposed linear features would primarily run along existing corridors and rights of way, including roadways, rail lines, and existing transmission lines. Only portions of each of the two new transmission line routes would be constructed on land that is currently in agriculture. Agricultural lands surrounding the project site include several fields of nut trees, including one field of almond trees directly south of APP.

A2PP laydown area would be located to the immediate ~~north~~ west of the proposed project site and would be approximately ~~1.85~~ 4.6 acres in size. Process water and wastewater connections would be located in the existing APP facilities. Natural gas would be provided via a 11.6 mile-long pipeline that would ~~run south along Morgan Road, west along East Zeering Road, south along Bystrum Road and west along West Harding Road , south along an unnamed farm road for 0.3 miles, west through a farm field for 0.5 mile and finally south on an unnamed farm road_msocom_1#_msocom_1 for approximately 0.7 mile to connect to PG&E's existing Line #215 at West Bradbury Road~~ take the following route: from the meter set, the gas pipeline would exit the existing Almond Power Plant boundary and turn east for approximately 0.6 mile paralleling Turlock Irrigation District (TID) Lateral #2. At the intersection of TID lateral #2 and Morgan Road, the gas pipeline would turn south and continue along Morgan Road for approximately 3 miles. The gas pipeline would then turn west on East Zeering Road for approximately 0.5 mile, and then turn south on Bystrum Road and on unpaved farm access roads for approximately 4.5 miles, before turning west on W. Harding Road (paralleling Harding Drain) for approximately 1.5 miles. Next, the gas pipeline would turn south on an unnamed farm road for approximately 0.7 mile, before joining with PG&E's Line #215 at W. Bradbury Road. PG&E will also construct a 1.8 mile gas pipeline reinforcement located on the west side of the San Joaquin River (Figure 1, DR Set 1D, Attachment DR 18-1; CH2MHILL2009k). Two new transmission lines have been proposed: an approximately 0.9-mile-long 115 kV transmission line (Corridor 1), and an approximately 1.2-mile-long, 115-kV transmission line (Corridor 2) (see Figure 1.1-3; CH2MHILL2009k).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section provides a discussion of the potential direct, indirect, and cumulative impacts to soil and water resources that may result from construction, operation, and maintenance of the proposed A2PP. While all projects would likely have impacts, the goal is to limit any adverse impacts to an insignificant or acceptable level, or to avoid them altogether, if possible. Staff's analysis of potential impacts consists of a brief description of the potential impact, an analysis of the relevant facts, and application of the threshold criteria for significance to the facts. Mitigation measures may be necessary to reduce potentially significant impacts to a level of insignificance. If mitigation is warranted, staff provides a summary of TID's proposed mitigation and a discussion of the adequacy of the proposed mitigation. Where necessary, staff presents additional or alternative mitigation measures or recommends specific conditions of certification related to a potential impact and any required mitigation measures.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff evaluated the potential impacts to soil and water resources including the effects of construction and operation activities that could result in erosion of soils, the deposition of sediments into surface waters or the contamination of either groundwater or surface water. Staff also evaluated the potential of the project's proposed water use to cause a significant depletion or degradation of local and regional water resources.

To evaluate if significant impacts to soil or water resources would occur, staff assessed:

- Whether construction or operation would lead to accelerated wind or water erosion and sedimentation.
- Whether the project would exacerbate flood conditions in the vicinity of the project.
- Whether the project's water use would cause a substantial, or potentially substantial, adverse change in the quantity or quality of groundwater or surface water.
- Whether project construction or operation would lead to degradation of surface or groundwater quality.
- Whether the project would comply with all applicable LORS.

These criteria are based on the California Environmental Quality Act (CEQA) Guidelines and performance standards (CCR 2009). The threshold of significance for project impacts is based on the ability of the project to be built and operated without violating applicable erosion, sedimentation, flood, surface or groundwater quality, water supply, or wastewater discharge standards. The federal, state, and local LORS and policies presented in **Soil and Water Resources Table 1** represent the applicable standards used for the A2PP analysis. These LORS support a comprehensive regulatory system, with adopted standards and established practices designed to prevent or minimize adverse impacts to soil and water resources. For those impacts that exceed standards or result in a significant adverse impact, conditions of certification may be necessary to ensure compliance with standards or reduce the impacts to a less than significant level.

Staff's analysis, determination of potential impacts, and evaluation of appropriate mitigation measures relies on estimates and information provided by TID regarding the construction and operation of A2PP. Applicable scientific, technical, and LORS/policy-related literature and expert opinion was also consulted in the development of staff's analysis.

DIRECT/INDIRECT IMPACTS AND MITIGATION

This direct and indirect impact and mitigation discussion is divided into impacts related to construction and to operation. For each potential impact evaluation, staff briefly describes the potential effect and applies the threshold criteria for significance to its analysis of the project. If mitigation is warranted, staff provides a summary of TID's proposed mitigation and a discussion of the adequacy of the proposed mitigation. In the absence of TID's proposed mitigation or if mitigation proposed by TID is inadequate, staff mitigation measures are recommended. Staff also provides specific conditions of certification related to a potential impact and the required mitigation measures.

Construction Impacts and Mitigation

Construction of A2PP would include soil excavation, grading, installation of utility connections and the use of fresh water, primarily for dust suppression. Potential impacts to soils related to increased erosion or release of hazardous materials are possible during construction. Potential stormwater impacts could result if increased runoff flow rates and volume discharges from the site were to increase flooding offsite. Water quality could be impacted by discharge of eroded sediments from the site, discharge of hazardous materials released during construction, or migration of any existing hazardous materials present in the subsurface soil and groundwater. However, staff does not believe there would be any potential adverse impacts associated with soil and groundwater contamination that would be exacerbated by construction of the proposed A2PP project. Project construction water demand could affect quantity of surface water resources. Potential construction related impacts to soil, stormwater, and water quality or quantity, including the applicant's proposed mitigation measures and staff's proposed mitigation measures are discussed below.

Erosion Control and Stormwater Management

Construction activities for managing erosion and stormwater must be addressed to avoid potential adverse impacts to water quality and soil resources. Accelerated wind and water-induced erosion may result from earth-moving activities associated with construction of the proposed project. Alteration of the soil structure leaves soil particles vulnerable to detachment and removal by wind or water. Soil erosion can cause the loss of topsoil and can increase the sediment load in surface receiving waters downstream of areas affected by construction activity. Increasing the amount of impervious surfaces would increase the amount of runoff and peak discharges. Runoff from stormwater can also convey contaminants to soil, groundwater, and surface water if hazardous materials and waste are not properly stored, handled, and disposed.

Construction activity would increase short-term soil erosion. With the implementation of Best Management Practices (BMPs) including stabilizing construction entrances, applying water for dust suppression, placement of silt fencing, berms, and hay bales as needed, erosion would be reduced to less than significant and water quality would not be adversely affected by runoff from the site.

Staff recommends two conditions, **SOIL&WATER-1** & **-2,** which address mitigation measures designed to reduce any soil erosion and stormwater construction impacts to less than significant levels.

Condition of Certification **SOIL&WATER-1** would require the project owner to comply with all of the requirements of the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity, including the development and implementation of a Storm Water Pollution Prevention Plan for Construction.

To qualify for the NPDES statewide General Permit for Storm Water Discharges Associated with Construction Activity (General Construction Permit), prior to construction TID would be required to develop a Construction SWPPP to prevent the offsite migration of sediment and other pollutants, and to reduce the effects of runoff from the laydown sites to offsite areas. Successful implementation of the SWPPP would ensure that construction impacts to soil resources are mitigated to a less-than-significant level. SWPPP procedures include submitting a Notice of Intent (NOI) to the State Water Resources Control Board (SWRCB~~)~~ and developing the SWPPP prior to the start of construction activities. The construction SWPPP would also be submitted to the Stanislaus County Stormwater Management Engineer for review.

The construction sequence of taking the existing operational stormwater retention basin offline and constructing the new retention basin should be described in the Drainage, Erosion, and Sediment Control Plan (DESCP~~)~~ project schedule recommended by staff in Condition of Certification **SOIL&WATER-2**. Condition of Certification **SOIL&WATER-2** requires the project owner to obtain Compliance Project Manager (CPM) approval for a site-specific final DESCP that addresses all project elements. Compliance with the requirements of this condition would reduce potential soil erosion and stormwater quality impacts to less than significant for the construction phase of the project.

Temporary Erosion Control Measures

Temporary erosion control measures would be implemented at the start of construction, and would be evaluated, inspected and maintained during construction. TID suggests these BMP measures would include silt fences, fiber rolls, and mulching. TID would not utilize temporary stormwater runoff detention or sedimentation basins, drainage diversion, and other large-scale sediment traps due to the relatively small size of the construction site, level topography, and density of paved areas surrounding the site. These temporary erosion control measures would be removed from the site after the completion of construction or converted to permanent BMPs.

During construction of the project, dust erosion control measures would be implemented to minimize the wind-blown loss of soil from the site. TID states that water of a quality equal to or better than existing surface runoff would be sprayed on the soil in construction areas to control dust.

Sediment barriers slow runoff and trap sediment. TID proposes to place sediment barriers, such as straw bales, sand bags, straw wattles, and silt fences around sensitive areas to prevent contamination by sediment-laden water. They would be placed downstream of disturbed areas, at the base of exposed slopes, and along streets and property lines below the disturbed area.

Since the site would be constructed on relatively level ground, TID would not utilize sediment barriers around the entire perimeter of the site; however, they would place some barriers in locations where onsite to offsite drainage could occur to prevent sediment from leaving the site. TID states that sediment barriers would be properly installed (staked and keyed), then removed or used as mulch after construction. Any soil stockpiles, including sediment barriers around the base of the stockpiles, would be stabilized and covered. Staff believes that with the implementation of BMPs suggested in the draft construction SWPPP and execution of Condition of Certification **SOIL&WATER-1**, temporary erosion control measures would satisfy all applicable LORS and reduce soil and water resources impacts to less than significant.

Laydown Areas

The area proposed for the A2PP construction laydown is approximately ~~1.85~~ 6.4 acres and would be located ~~north~~ west of the proposed project site. There are nearly level conditions at the site and laydown areas; however, due to compaction from previous activity on the site, the soils are expected to have slow to very slow permeability (and consequently, high runoff). TID expects the laydown area to be graded within one month and then be immediately covered with gravel or other material to permit wet season use and to prevent subsequent wind erosion losses.

Vehicle traffic and equipment staging would result in soil compaction in the laydown area. Soil compaction increases soil density by reducing soil pore space. This, in turn, exacerbates the ability of the soil to absorb precipitation and transmit gases for respiration of soil microfauna. Soil compaction can result in increased runoff, erosion, and sedimentation. TID proposes to store heavy equipment on dunnage (loose scrap material that provides ventilation) to protect it from ground moisture. Compaction beneath the laydown area can also be mitigated by removing and stockpiling topsoil for later reuse and by deep ripping the subsoil after removing the material and gravel covering. Given the limited area over which permanent compaction would occur, it is considered that this impact would be less than significant. It is also assumed that soil loss would be negligible from the laydown areas once it is covered.

The highest potential for soil loss would occur immediately following grading and prior to the cover material being placed or during the period following the end of construction, when gravel is removed. TID has described the existing laydown area as bare soil and that the laydown area would be returned to its current condition. Given the former construction activity at the site, it is likely that the soil structure in this area may be significantly changed. With the implementation of Conditions of Certification **SOIL&WATER-1** and **SOIL&WATER-2**, staff believes any potential significant adverse impacts caused by erosion or storm water discharge during construction of the project would be mitigated.

Water Supply

The primary use of water for site construction would be dust control. TID would use fresh water from either the onsite fire system at the APP or TID's Lateral #2 irrigation canal for all non-domestic construction water uses. Construction water used for dust control and soil compaction would not result in discharge. TID estimates the daily average and maximum construction water use to be 36,000 and 144,000 gallons, respectively. The maximum water use for the entire 12-month construction period would be 52.56 million gallons (161.3 AF). Tank and pipeline hydrostatic testing at the A2PP site would require 18,200 gallons and the volume required to flush all the pipelines would be 36,400 gallons. However, a relatively limited amount of water (an average of approximately 50 gallons per minute and approximately 200 gallons per minute per 1 hour for dust control and soil compaction, at peak use) would be needed daily.

The total amount of water needed for construction would equate to less than 0.5 AF per day. Due to the low production rate relative to the capable production of the local aquifer, use of the APP onsite well via the APP fire system tank would not impact other users or result in significant impacts to the groundwater basin. The use of surface water managed and distributed by TID from Lateral #2 for construction would not impact TID's ability to meet delivery requirements to other users, since average daily requirements would be about 0.11 cfs (50 gpm). The canal normally flows at 60 to 80 cfs during the irrigation season, which ideally would coincide with peak construction activity. During the rainy season, the canal flows at about 5 cfs. Drinking water would be supplied by an outside water delivery service.

Wastewater and Sanitary Waste

During the construction period, TID states that all sanitary waste would be collected in portable toilets (no discharge) supplied by a licensed contractor for collection and disposal at an appropriate receiving facility. Equipment wash water would also be collected and disposed of offsite; therefore, there would be no impacts from disposal of sanitary wastewater. Handling and disposal or use of ~~Staff recommends~~ TID ~~handle the~~ wastewater from hydrostatic testing shall be managed <u>consistent with State Water Resources Control Board Water Quality Order No. 2003-003-DWQ requirements (SWRCB 2003)</u> ~~similar to the handling of the equipment wash water.~~ Handling, storing and disposal of all construction wastewater would be fully described in the construction SWPPP; required as part of Condition of Certification **SOIL&WATER-1**. Staff believes implementation of this condition would be sufficient to ensure there were no impacts due to construction wastewater.

<u>Operational Impacts and Mitigation</u>

Operation of A2PP could lead to potential impacts to soil, stormwater runoff, water quality, water supply, and wastewater treatment. Soils may be potentially impacted through erosion or the release of hazardous materials used in the operation of A2PP. Stormwater runoff from the A2PP site could result in potential impacts if increased runoff flow rates and volumes discharged from the site increase downstream flooding. Water quality could be impacted by discharge of eroded sediments from the A2PP site, or discharge of hazardous materials released during operation. Water supply for plant processes, cooling, fire protection and landscape irrigation could lead to potential quantity or quality impacts to regional groundwater or surface water resources. Potential impacts to soil, stormwater, water quality, water supply, and wastewater related to the operation of A2PP, including the applicant's proposed mitigation measures and staff's proposed mitigation measures, are discussed below.

Stormwater

The development of A2PP would result in approximately 4.6 additional acres of impervious surfaces on the project site. However, the increase in the amount of impervious surface is not expected to significantly change the amount or timing of runoff from the A2PP project site as the site would be built on relatively level ground.
The existing APP stormwater drainage system would be expanded to accommodate the A2PP plant and the existing APP onsite retention pond would be relocated to the northern side of the A2PP site to incorporate stormwater drainage from both APP and A2PP. Because stormwater would be collected and discharged to the onsite retention pond, the A2PP project would not result in substantial erosion, siltation, or flooding on- or offsite; therefore, staff believes that with the implementation of Conditions of Certification **SOIL&WATER-2** and **SOIL&WATER-3**, operational impacts to drainage patterns would be less than significant. **SOIL&WATER-2** requires the project owner to identify results of stormwater BMP monitoring and maintenance activities and **SOIL&WATER-3** compels TID to comply with all requirements of the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity.

Water Supply

The Second Amendment to the Water Services Agreement (Amendment 2) (CH2MHILL2009i), modifies the Water Services Agreement (Agreement) (CH2MHILL2009f) and the First Amendment to the Water Services Agreement (Amendment 1) (CH2MHILL2009f) between TID and the City of Ceres. Amendment 2 permits the use of up to 1,135,000 gallons per day of (primary-treated) reclaimed water, via pumping through an extraction well adjacent to the Ceres WWTP percolation-evaporation (P-E) basins, as a process water supply source. The Agreement states that Ceres WWTP P-E basins will have enough capacity at all times during the year. Staff confirmed that the 12 acre P-E ponds have a percolation capacity of 3.5 inches per day, which is sufficient to meet TID's expansion pumping needs (Riddell2009). TID has stated that service from Ceres WWTP provides a high level of reliability of reclaimed water and no back-up water source is identified for A2PP. Staff confirmed that the existing reclaimed water treatment process at APP is not currently permitted and that the Central Valley RWQCB does not require the treatment process to be permitted. Staff finds that the A2PP use and delivery of reclaimed water using the existing APP facilities for delivery and treatment would also not require additional Central Valley RWQCB permits (CH2MHILL2010, Izzo2010). The basis for this finding is that the effluent from the treatment process is discharged to the permitted Ceres WWTP.

Staff reviewed the Applicant's steady-state, 3-dimensional, finite-element groundwater model (CH2MHILL2009g) and agrees with the conclusion that 95% of the process water supply pumped from the extraction well originates from the P-E basins.
The Agreement is based on mutual benefits provided to TID and the City of Ceres. TID is offered an economical source of reclaimed water for use in power plant processes and the pumping increases the percolation rate of the WWTP P-E basins. The added demand for A2PP water helps draw down the local groundwater table in the vicinity of the Ceres WWTP to drive down mounding that inhibits percolation capacity. (Riddell2009). The Agreement allows TID to discharge process wastewater (about 50-60% of the volume extracted) directly to the P-E basins. Michael Riddell, Ceres WWTP Wastewater Systems Supervisor, stated that the terms of the Agreement allow TID to discharge process wastewater into the P-E basins only while the extraction well is in operation as there would be no benefit to Ceres WWTP when the extraction well was not increasing the percolation rate of the P-E basins (Riddell2009). This flow cycle of draw down and return flow has a net benefit that increases wastewater storage capacity in the P-E basins. ~~Therefore, Staff is concerned that although Amendment 2 acknowledges the capacity of Ceres WWTP to provide a sufficient volume of water for the proposed A2PP, the Ceres WWTP's WDRs may be revised by the Central Valley RWQCB in the future. Should changes to water quality standards in those WDRs prohibit the inclusion of A2PP's waste discharge into the Ceres WWTP, a new process water supply source or pretreatment at the project prior to discharge to the Ceres WWTP would be needed.~~

The Agreement between TID and the City of Ceres requires meters to record the daily flows of reclaimed water and process water returned to the plant. Condition of Certification **SOIL&WATER-4** requires TID to provide verification of operational metering devices and complete an annual Water Use Summary to be provided in annual compliance reports.

Wastewater and Sanitary Waste

Amendment 2 (CH2MHILL2009i) allows TID to discharge up to a maximum of 560,000 gallons (1.72 AF) per day with a maximum annual total up to 52,000,000 gallons per year (160 AFY) of process wastewater from the combined existing APP facility and proposed A2PP facility directly to the Ceres WWTP P-E basins. With the addition of A2PP, the demand on the 6 inch return line is approximately 314,000 gallons per day gpd (0.964 AF) (CH2MHILL2009f), well under the maximum daily discharge allowed in Amendment 2. The City of Ceres has agreed to accept the process wastewater from A2PP with the understanding that the Ceres WWTP could continue to meet the water quality standards of their current WDRs. Currently, no numerical limitations are in place for constituents in the Ceres WWTP's WDRs (CH2MHILL2009f), other than what is contained in the WDRs. Therefore, the Almond 2 project would comply with existing WDRs. Staff notes that during the life of the project the Ceres WWTP may be required to revise the WDR's. This could in turn affect the quality of waste water that can be discharged from the project to the WWTP. At this point, changes in the WDRs are too speculative to predict. However, should changes to water quality standards in those WDRs prohibit the inclusion of A2PP's waste discharge into the Ceres WWTP, a new process water supply source or pretreatment at the project prior to discharge to the Ceres WWTP would be needed, and therefore, possibly a project amendment.

Waste Discharge Requirements (WDRs), issued by the Central Valley RWQCB, in the San Joaquin Valley are being updated (Landau2009) and these changes will have an effect on the Ceres WWTP and ultimately could impact the Water Services Agreement with TID. Mr. Landau could not confirm the exact date that new WDRs for Ceres WWTP would be completed; however, WDR changes are anticipated within the lifespan of the A2PP project. The Central Valley RWQCB is generally concerned about salinity in the Central Valley (Wass2009; Landau2009) and staff is concerned that this may result in changes to treatment methods and water quality standards at the Ceres WWTP as it is a primary-treated system that may leach large quantities of salts into the soils and local shallow aquifer system. Staff believes that if the Ceres WWTP is required to improve their treatment methods the City could impose restrictive water quality standards on the process wastewater from A2PP as provided for in Amendment 2 (Landau2009).

Modifications of the WDRs for Ceres WWTP or a change to the County's overall treatment operations could disrupt process wastewater service via the existing 6-inch discharge pipe to the Ceres WWTP. Staff is primarily concerned that updated WDRs would make direct discharge into the P-E basins prohibitive if the quality of the process wastewater exceeds the Ceres WWTP's ability to meet new Regional Board requirements. If pre-treatment of wastewater to comply with stricter water quality standards in the Ceres WWTP P-E basins cannot be accomplished, TID would have to find a different means of wastewater disposal. Based on the speculative nature of future WDR modifications A2PP has objected to data requests from staff that are intended to understand what treatment processes would be implemented to comply with new WDR.

Staff notes that future changes in water quality and WDR's could result in limitations on discharges on A2PP discharges and require changes in project operation. However, it is currently unknown how these changes would be implemented by the RWQCB and it is difficult to analyze any potential changes that would be required for project compliance.

Any changes in response to new regulatory requirements could result in the need for a project modification or amendment. Staff has included Condition of Certification **SOIL&WATER-5** that requires the project owner to report to the CPM any violations of wastewater discharge from A2PP to the City of Ceres. The Condition also requires notification to the CPM for any suspensions, nullifications, or amendments to the Water Services Agreement (Amendment 2) (CH2MHILL2009i).

A2PP sanitary waste water will utilize the existing septic tank on APP. Staff has determined that the existing septic tank / leach field is sized appropriately to handle the additional load.

CUMULATIVE IMPACTS AND MITIGATION

Cumulative impacts consist of impacts that may occur as a result of the proposed project in combination with impacts from other past, present and reasonably foreseeable future projects. Cumulative impacts can result from individually minor, but collectively significant actions taking place over time.

Temporary and permanent disturbances associated with construction of the proposed project would cause accelerated wind- and water-induced erosion. However, staff has concluded that the implementation of proposed mitigation measures, the SWPPP and the DESCP would ensure that the project would not contribute significantly to cumulative erosion and sedimentation impacts.

The industrial wastewater and contact stormwater from the A2PP site would be routed to the existing onsite holding tank and hauled offsite for disposal at a licensed facility. All sanitary waste water would be discharged into the existing APP septic tank / leach field. Therefore, no wastewater-related cumulative impacts are expected. The stormwater discharge would be retained on site and would not exacerbate flooding conditions in the area.

A2PP would use percolated wastewater pumped from an existing extraction well near the Ceres WWTP primary-treated percolation-evaporation basins. APP is currently the only user of this wastewater, and since A2PP would be an expansion of that power plant operation, staff does not expect the increased pumping rate to negatively affect any other water users.

No significant cumulative impacts are expected to result from the A2PP project. The A2PP project would use less than 13.2 million gallons (40.51 AF) of fresh water for construction, assuming average daily use, during the entire 12 month construction period. Though the A2PP would be a wet-cooled system, TID would be reclaiming wastewater that has percolated to groundwater near the Ceres WWTP P-E basins. The requirements for fresh water include minimal use of groundwater, for sanitary water purposes, to be pumped via the existing well at the APP site. The A2PP site would not significantly alter offsite runoff quantity or quality, nor would it significantly impact soil resources as the site was previously disturbed. Soils not covered by the plant buildings, pavement, and ancillary improvements would not be changed over the long-term. Staff believes A2PP would not contribute to a cumulative soil and water resources impact.

COMPLIANCE WITH LORS

The Energy Commission's power plant certification process requires staff to review each of the proposed project's elements for compliance with LORS and policies. Staff has reviewed the project elements and concludes that the proposed A2PP project would comply with all applicable LORS addressing protection of water resources, storm water management, and erosion control, as well as drinking water, use of freshwater, and wastewater discharge requirements, as long as staff's proposed conditions of certification are adopted and implemented. Summary discussions of project compliance with significant LORS and policies are provided below.

CLEAN WATER ACT

Staff has determined that the A2PP project would satisfy the requirements of the General National Pollutant Discharge Elimination System permit with the adoption of Conditions of Certification **SOIL&WATER-1 and SOIL&WATER-3**, which require the development and implementation of SWPPPs for construction and industrial activity.

PORTER-COLOGNE WATER QUALITY CONTROL ACT

Staff has concluded that A2PP would satisfy the applicable requirements of the Porter-Cologne Water Quality Control Act and adequately protect the beneficial uses of waters of the state through implementation of federal, state, and local requirements for management of storm water discharges and pollution prevention and compliance with local grading and erosion control requirements, and compliance with local onsite wastewater treatment system (septic system) requirements.

CALIFORNIA WATER CODE

Staff has determined that the A2PP site would comply with all sections of the California Water Code addressed in **Soil and Water Resources Table 1**. The A2PP project would utilize reclaimed water for all process and cooling water needs.

ENERGY COMMISSION WATER POLICY

California Constitution

Article X, Section 2 calls for water to be put to beneficial use, and that "waste or unreasonable use or unreasonable *method of use* be prevented." (Cal. Const., art. X, § 2; emphasis added.) The article also limits water rights to reasonable use, including reasonable methods of use. (*Ibid*.) Groundwater is subject to reasonable use. (*Katz v. Walkinshaw* (1903) 141 Cal. 116.)

Warren-Alquist Act

Section 25008 of the Commission's enabling statutes echoes the Constitutional concern, by promoting "all feasible means" of water conservation and "all feasible uses" of alternative water supply sources. (Pub. Resources Code § 25008.)

Integrated Energy Policy Report

In the 2003 Integrated Energy Policy Report ("IEPR" or "Report"), the Commission reiterated certain principles from SWRCB's Resolution 75-58, discussed below, and clarified how they would be used to discourage use of fresh water for cooling power plants under the Commission's jurisdiction. The Report states that the Commission will approve the use of fresh water for cooling purposes only where alternative water supply sources or alternative cooling technologies are shown to be "'environmentally undesirable'" or "'economically unsound.'" (IEPR (2003), p. 41.) In the Report, the Commission interpreted "environmentally undesirable" as equivalent to a "significant adverse environmental impact" under CEQA, and "economically unsound" as meaning "economically or otherwise infeasible," also under CEQA. (IEPR, p. 41.) CEQA and the Commission's siting regulations define feasible as "capable of being accomplished in a successful manner within a reasonable amount of time," taking into account economic and other factors. (Cal. Code Regs., tit. 14, § 15364; tit. 20, § 1702, subd. (f).) (IEPR, p. 39.)

State Water Resources Control Board Resolutions

In 1975, the Board determined that surface water with total dissolved solids ("TDS") of 1,000 mg/l or less should be considered fresh water. (Resolution 75-58) One express purpose of that Resolution was to "keep the consumptive use of fresh water for powerplant cooling to that *minimally essential*" for the welfare of the state. (*Ibid*; emphasis added.) In 1988, the board designated all groundwater and surface waters of the States as potential sources of drinking water, worthy of protection for current or future beneficial uses, except where: (a) the total dissolved solids are greater than 3,000 milligrams per liter, (b) the well yield is less than 200 gallons per day (gpd) from a single well, (c) the water is a geothermal resource, or in a water conveyance facility, or (d) the water cannot reasonably be treated for domestic use using either best management practices or best economically achievable treatment practices. (Resolution 88-63.) State Water Resources Control Board Resolution 2009-0011 encourages and promotes reclaimed water use for non-potable purposes. The A2PP project uses three combustion turbines operating in simple cycle mode without a steam cycle. During operation, the applicant estimates approximate 293 acre feet of water will be required each year. Reclaimed water is available from the City of Ceres.

Because the project would pump groundwater solely for sanitary uses onsite, and because the project is using reclaimed water for project processes, including cooling, staff finds that the Almond 2 project complies with state and Energy Commission water policies.

NOTEWORTHY PUBLIC BENEFITS

The A2PP project's proposed use of reclaimed groundwater near the Ceres WWTP would offer an operational benefit to the wastewater treatment process. The added demand for A2PP groundwater helps draw down the local groundwater table in the vicinity of the Ceres WWTP to drive down mounding that inhibits percolation capacity in the Ceres WWTP P-E ~~Percolation-Evaporation~~ basins, especially during the winter months (Riddell2009).
~~Neither the applicant nor staff has identified any noteworthy benefits to soil or water resources that would be provided by the project.~~

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No comments on Soil and Water Resources were received.

CONCLUSIONS

Based on its assessment of the proposed TID Almond 2 Power Plant (A2PP) project, staff concludes the following:

- Implementation of Best Management Practices (BMPs) during A2PP construction and operation in accordance with effective SWPPPs and a DESCP would avoid significant adverse effects that could be caused by transport of sediments or contaminants from the A2PP site and associated linear facilities by wind or water erosion.
- The proposed reclaimed water supply for the project would not cause a significant adverse environmental impact on current or future users of the water supply.
- ~~The Waste Discharge Requirements for the City of Ceres Wastewater Treatment Plant may be altered by the Central Valley Regional Water Quality Control Board in the future, which could affect the both the water supply and wastewater disposal for the A2PP site.~~
- The proposed project would be constructed to comply with 100-year flood requirements and would not exacerbate flood conditions in the vicinity of the project.
- ~~The proposed project would comply with all applicable federal, state and local laws, ordinances, regulations and standards with the adoption of the recommended conditions of certification.~~
- A2PP would not result in any unmitigated project-specific or cumulative significant adverse impacts to soil or water resources with adoption of the conditions of certification.
- The project complies with the state water policies by using reclaimed water.

Staff concludes that A2PP would not result in any unmitigated project-specific or cumulative significant adverse impacts to soil or water resources and would comply with all applicable laws, ordinances, regulations and standards (LORS) if all of the recommended conditions of certification are adopted by the Commission and implemented by TID.

PROPOSED CONDITIONS OF CERTIFICATION

SOIL&WATER-1: The project owner shall comply with the requirements of the General National Pollutant Discharge Elimination System (NPDES) permit for discharges of storm water associated with construction activity. The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the construction of the entire TID Almond 2 Power Plant (A2PP).

Verification: At least 60 days before construction begins, the project owner shall submit a copy of the construction SWPPP to the Stanislaus County Public Works

Department, ~~Stormwater Management Engineer~~ for review, and concurrently to the CPM for approval. At least 30 days before construction begins, the project owner shall submit copies to the Compliance Project Manager (CPM) of all correspondence between the project owner and the Central Valley Regional Water Quality Control Board (RWQCB) regarding the General NPDES permit for the discharge of storm water associated with construction activities. This information shall include copies of the Notice of Intent and the Notice of Termination sent to the State Water Resources Control Board for the project construction.

SOIL&WATER-2: The project owner shall develop a site-specific DESCP that ensures protection of water quality and soil resources of the project site and all linear facilities for both the construction and operation phases of the project. This plan shall address appropriate methods and actions, both temporary and permanent, for the protection of water quality and soil resources, demonstrate no increase in offsite flooding potential, meet local requirements, and identify all monitoring and maintenance activities. Monitoring activities shall include routine measurement of the volume of accumulated sediment in the stormwater retention basin. Maintenance activities must include removal of accumulated sediment from the retention basin when an average depth of 0.5 feet of sediment has accumulated in the retention basin. The plan shall be consistent with the grading and drainage plan as required by Condition of Certification **CIVIL-1**. The DESCP shall contain the following elements. All maps shall be presented at a legible scale no less than 1" = 100'.

- ***Vicinity Map*** – A map shall be provided indicating the location of all project elements with depictions of all significant geographic features to include watercourses, washes, irrigation and drainage canals, and sensitive areas.
- ***Site Delineation*** – The site and all project elements shall be delineated showing boundary lines of all construction areas and the location of all existing and proposed structures, pipelines, roads, and drainage facilities.
- ***Watercourses and Critical Areas*** – The DESCP shall show the location of all nearby watercourses including washes, irrigation and drainage canals, and drainage ditches, and shall indicate the proximity of those features to the construction site.
- ***Drainage*** – The DESCP shall include hydrologic calculations for onsite areas and offsite areas that drain to the site; include maps showing the drainage area boundaries and sizes in acres, topography and typical overland flow directions, and show all existing, interim, and proposed drainage infrastructure and their intended direction of flow. Provide hydraulic calculations to support the selection and sizing of the drainage network, retention facilities and best management practices (BMPs). Spot elevations shall be required where relatively flat conditions exist. The spot elevations and contours shall be extended off site for a minimum distance of 100 feet in flat terrain or to the limits of the offsite drainage basins that drain toward the site.

- ***Clearing and Grading*** – The plan shall provide a delineation of all areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slopes, locations, and extent of all proposed grading as shown by contours, cross sections, cut/fill depths or other means. The locations of any disposal areas, fills, or other special features shall also be shown. Existing and proposed topography tying in proposed contours with existing topography shall be illustrated. The DESCP shall include a statement of the quantities of material excavated at the site, whether such excavations or fill is temporary or permanent, and the amount of such material to be imported or exported or a statement explaining that there would be no clearing and/or grading conducted for each element of the project. Areas of no disturbance shall be properly identified and delineated on the plan maps.
- ***Project Schedule*** – The DESCP shall identify on the topographic site map the location of the site-specific BMPs to be employed during each phase of construction (initial grading, project element excavation and construction, and final grading/stabilization). Separate BMP implementation schedules shall be provided for each project element for each phase of construction.
- ***Best Management Practices*** – The DESCP shall show the location, timing, and maintenance schedule of all erosion- and sediment-control BMPs to be used prior to initial grading, during project element excavation and construction, during final grading/stabilization, and after construction. BMPs shall include measures designed to control dust and stabilize construction access roads and entrances. The maintenance schedule shall include post-construction maintenance of treatment-control BMPs applied to disturbed areas following construction.
- ***Erosion Control Drawings*** – The erosion control drawings and narrative shall be designed, stamped and sealed by a professional certified engineer or erosion-control specialist.

Verification: ~~No later than 90 days prior to start of construction, the project owner shall submit a copy of the DESCP to Stanislaus County for review and comment.~~ No later than 60 days before the start of construction, the project owner shall submit a copy of the DESCP to the CPM for review and approval. ~~The project owner shall promptly submit a copy of any comments from Stanislaus County regarding the DESCP to the CPM.~~ During construction, the project owner shall provide an analysis in the monthly compliance report on the effectiveness of the drainage-, erosion- and sediment-control measures and the results of monitoring and maintenance activities. Once operational, the project owner shall provide in the annual compliance report information on the results of stormwater ~~BMP~~ facilities monitoring and maintenance activities. The information required in the DESCP may be included as part of the SWPPP. ~~The operational SWPPP may be combined with the DESCP in an effort to simplify the annual compliance reporting and CPM review. A combined DESCP/SWPPP would be verified under SOIL&WATER-3.~~

SOIL&WATER-3: The project owner shall comply with the requirements of the General NPDES permit for discharges of storm water associated with industrial activity. The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the operation of the site. The project owner shall ensure that only stormwater is discharged onto the site. The project owner shall comply with the requirements of the general NPDES permit for discharges of storm water associated with industrial activity. The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the operation of the site.

Verification: At least 30 days prior to commercial operation, the project owner shall submit the operational Storm Water Pollution Prevention Plan for the A2PP site to the CPM. Within 10 days of its mailing or receipt, the project owner shall submit to the CPM any correspondence between the project owner and the Central Valley RWQCB about the general NPDES permit for discharge of storm water associated with industrial activity. This information shall include a copy of the notice of intent sent by the project owner to the State Water Resources Control Board. A letter from the Central Valley RWQCB indicating that there is no requirement for a general NPDES permit for discharges of storm water associated with industrial activity would satisfy this condition.

SOIL&WATER-4: Water used for project operation processing shall exclusively be reclaimed water from the City of Ceres Wastewater Treatment Plant. Pumping or purchasing groundwater for this supply source is prohibited. Water use shall not exceed 514 acre-feet per year. The project owner shall monitor and record the total water used on a monthly basis. For calculating the annual water use, the term “year” will correspond to the date established for the annual compliance report submittal.

~~The project owner shall maintain metering devices as part of the water supply and distribution systems to monitor and record, in gallons per day, the total volume(s) of water supplied to A2PP from the City of Ceres. Those metering devices shall be operational for the life of the project.~~

~~For the first year of operation, the project owner shall prepare an annual Water Use Summary, which will include the monthly average of daily water usage in gallons per day, and total water used by the project on a monthly and annual basis in acre-feet. For subsequent years, the annual Water Use Summary shall also include the annual water used by the project in prior years. The annual Water Use Summary shall be submitted to the CPM as part of the annual compliance report (ACR).~~

Verification: At least 60 days prior to commercial operation of A2PP, the project owner shall submit to the CPM evidence that metering devices are operational on the water supply and distribution systems. ~~The project owner, in the annual compliance report, shall provide a Water Use Summary that states the source and quantity of water used on a monthly basis and on an annual basis in units of acre-feet. The ACR shall also report the average daily maximum water usage in gallons per day for each month. Prior annual water use shall be reported in subsequent annual compliance reports~~.

<u>The project owner shall maintain metering devices as part of the water supply and distribution systems to monitor and record, in gallons per day, the total volume(s) of</u>

water supplied to A2PP from the City of Ceres. Those metering devices shall be operational for the life of the project.

For the first year of operation, the project owner shall prepare an annual Water Use Summary, which will include the monthly average of daily water usage in gallons per day, and total water used by the project on a monthly and annual basis in acre-feet. For subsequent years, the annual Water Use Summary shall also include the annual water used by the project in prior years. The annual Water Use Summary shall be submitted to the CPM as part of the annual compliance report (ACR).

SOIL&WATER-5: The A2PP process wastewater will discharge to the Ceres WWTP Percolation-Evaporation basins at a maximum discharge of 560,000 gallons per day per the City of Ceres, CA and Turlock Irrigation District Water Services Agreement and its Amendments. ~~In the event the Water Services Agreement is suspended, nullified, or amended, the project owner shall provide the CPM with all information and documentation related to A2PP water supply or waste discharge to the City of Ceres Waste Water Treatment Plant (WWTP).~~ During operation, any monitoring reports provided to the City of Ceres shall also be provided to the CPM. The CPM shall be notified of any violations of discharge limits or amounts.

Verification: During A2PP operation, the project owner shall submit to the CPM any wastewater quality monitoring reports required by the City of Ceres, in the annual compliance report. The project owner shall submit any notice of violations from the City of Ceres to the CPM within 10 days of receipt and fully explain the corrective actions taken in the annual compliance report. The project owner shall also promptly provide to the CPM copies of all correspondence between the Ceres WWTP and TID related to suspensions, nullifications, or amendments to the Water Services Agreement.

REFERENCES

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CH2MHILL2009i – CH2MHILL/S. Madams (tn: 53901). Data Response Set 1C – Responses to CEC Staff Data Requests 61b, 68 & 72. Dated 10/30/09. Submitted to CEC/Docket Unit on 10/30/09.

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TID2009a –Turlock Irrigation District/ R. Baysinger (tn: 51502). Application for Certification, Volume 1& 2. Dated 5/11/09. Submitted to CEC/Docket Unit on 5/11/09.

SWRCB 2003 - State Water Resources Control Board Water Quality Order No. 2003 – 0003 – DWQ. Statewide General Waste Discharge Requirements (WDRs) for Discharges to Land With a Low Threat to Water Quality (General WDRs)

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Wass2009—Central Valley Regional Water Quality Control Board (CVRWQCB)/ Lonnie Wass, Supervising Engineer in Fresno office for CVRWQCB. Pers. comm. 08/28/2009.

WRCC2009—Western Regional Climate Center (WRCC). 2009. Modesto, California. Online Information: http://www.wrcc.dri.edu/cgi-bin/cliMAIN.pl?ca5738 Accessed: July 29, 2009.

DECLARATION OF
Felicia Miller

I, Felicia Miller declare as follows:

1. I am presently employed by the California Energy Commission in the Facilities Siting Office of the Energy Facilities Siting Division as Project Manager.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared staff testimony on Introduction, Project Description and Executive Summary for the Almond 2 Power Power Plant project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed herein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently hereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/7/10 Signed: Felicia Miller

At: Sacramento, California

DECLARATION OF
James Brewster Birdsall

I, James Brewster Birdsall, declare as follows:

1. I am under contract with Aspen Environmental Group to provide environmental technical assistance to the California Energy Commission. Under Contract No. 700-08-001, I am serving as an Air Quality Specialist and Project Manager to provide Peak Workload Support for the Energy Facility Siting Program and for the Energy Planning Program and the Siting, Transmission, and Environmental Protection Division.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Air Quality and Greenhouse Gas Emissions** for the Almond 2 Power Plant Project based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 19, 2010 Signed: [signature]

At: San Francisco, California

DECLARATION OF
Tao Jiang, Ph.D., P.E.

I, Tao Jiang, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission and Environmental Protection Division, as an Air Resources Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on the **Air Quality** for the **Almond 2 Power Plant** project (09-AFC-2) based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 20, 2010

Signed: Tao Jiang

At: Sacramento, California

DECLARATION OF
David Bise

I, **David Bise**, declare as follows:

1. I am presently employed by the California Energy Commission in the **Environmental Protection Office** of the **Energy Facilities Siting Division** as a **Planner II**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Biological Resources Revised Staff Assessment** for the Almond 2 Project based on my independent analysis of the application and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

   I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 20, 2010 Signed: David Bise

At: Sacramento, California

DECLARATION OF
Kathleen Forrest

I, Kathleen Forrest declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission, and Environmental Protection Division as Cultural Resources Planner.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared staff testimony on Cultural Resources for the Almond 2 Power Plant project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed herein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently hereto.

   I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/23/10 Signed: Kathleen Forrest

At: Sacramento, California

DECLARATION OF
Michael D. McGuirt

I, Michael D. McGuirt, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission, and Environmental Protection Division as Cultural Resources Planner.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared staff testimony on Cultural Resources for the Almond 2 Power Plant project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed herein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently hereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/23/10 Signed:

At: Sacramento, California

DECLARATION OF
Alvin J. Greenberg, Ph.D.

I, **Alvin J. Greenberg, Ph.D.** declare as follows:

1. I am presently a consultant to the California Energy Commission, Energy Facilities Siting and Environmental Protection Division.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony and errata on the **Public Health, Hazardous Materials Management**, and **Worker Safety/Fire Protection** sections for the **Almond-2 Power Plant Application** based on my independent analysis of the amendment petition, supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/23/10 Signed: [signature]

At: Sacramento, California

DECLARATION OF

I, **Rick Tyler** declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting, Transmission, and Environmental Protection Division as a Senior Mechanical Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I supervised preparation of the staff testimony for Hazardous Materials Management and Worker Safety Fire Protection Sections for the Almond 2 Power Plant Project based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony and errata is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and errata and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 4/20/10 Signed: ____________________

At: Sacramento, California

DECLARATION OF
Jeanine Hinde

I, **Jeanine Hinde**, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission, and Environmental Protection Division as a Planner I.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Land Use** for the Almond 2 Project based on my independent analysis of the application and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 23, 2010 Signed: Jeanine Hinde

At: Sacramento, California

DECLARATION OF
Erin Bright

I, **Erin Bright**, declare as follows:

1. I am presently employed by the California Energy Commission in the **Engineering Office** of the Siting Transmission and Environmental Protection Division as a **Mechanical Engineer**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Facility Design** and **Noise and Vibration** for the **Almond 2 Power Plant Project** based on my independent analysis of the Application, supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 20, 2010 Signed: ______________________

At: Sacramento, California

DECLARATION OF
Kristin Ford

I, Kristin Ford declare as follows:

1. I am presently employed by the California Energy Commission in the Facilities Siting Office of the Energy Facilities Siting Division as a Planner I.

2. I prepared staff testimony for the Almond 2 Power Plant Project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

3. The information in the project description is correct, as the subject site is owned by Turlock Irrigation District.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/20/10 Signed:

At: Sacramento, California

DECLARATION OF
Vince Geronimo, PE

I, Vince Geronimo, declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Office of the Energy Facilities Siting Division as a Soil & Water Resources Specialist.

2. I helped prepare the staff testimony on the errata to staff assessment for Soil & Water Resources, for the Almond 2 Power Plant Project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

3. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

4. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 20, 2010 Signed: ______

At: Sacramento, California

DECLARATION OF
Rachel Cancienne, EIT

I, Rachel Cancienne, declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Office of the Energy Facilities Siting Division as a Soil & Water Resources Specialist.

2. I helped prepare the staff testimony on the errata to staff assessment for Soil & Water Resources, for the Almond 2 Power Plant Project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

3. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

4. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 21, 2010 Signed: Rachel C

At: Sacramento, California

DECLARATION OF
Dr. Obed Odoemelam

I, **Obed Odoemelam** declare as follows:

1. I am presently employed by the California Energy Commission in the Facilities Siting Office of the Energy Facilities Siting Division as Staff Toxicologist.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared staff testimony on Transmission Line Safety and Nuisance for the Almond 2 Power Power Plant project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed herein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently hereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 4/19/10 Signed: Odoemelam

At: Sacramento, California

DECLARATION OF
Marie McLean

I, Marie McLean, declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Office of the Siting, Transmission, and Environmental Protection Division as an Environmental Planner II.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on Traffic and Transportation for the Almond II Errata (09-AFC-2) based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 23, 2010 Signed: Marie McLean

At: Sacramento, California

DECLARATION OF
Ellen Townsend-Hough

I, **Ellen Townsend-Hough** declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Siting Office of the Siting Transmission& Environmental Protection Division as an Associate Mechanical Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on Waste Management for the Almond 2 Power Plant Project based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 26, 2010 Signed: [signature]

At: Sacramento, California

DECLARATION OF

Testimony of Dal Hunter, Ph.D., C.E.G.

I, **Dal Hunter, Ph.D., C.E.G.,** declare as follows:

1. I am presently employed as a subcontractor to Aspen Environmental Group, a contractor to the California Energy Commission, Systems Assessment and Facilities Siting Division, as an Engineering Geologist.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **GEOLOGY AND PALEONTOLOGY** for the **Turlock Irrigation District Almond 2 Power Plant Project** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 20, 2010 Signed:

At: Black Eagle Consulting, Inc.
Reno, Nevada

REGISTERED GEOLOGIST
ROBERT DALTON HUNTER
No. 1411
CERTIFIED ENGINEERING GEOLOGIST
STATE OF CALIFORNIA

exp 3.31.11

DECLARATION OF
SHAHAB KHOSHMASHRAB

I, **SHAHAB KHOSHMASHRAB**, declare as follows:

1. I am presently employed by the California Energy Commission in the **ENGINEERING OFFICE** of the Facilities Siting Division as a **MECHANICAL ENGINEER**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I participated in the preparation of the staff testimony on **Power Plant Reliability** for the **TID Almond 2 Power Plant** based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/27/10 Signed: ______________

At: Sacramento, California

DECLARATION OF
SHAHAB KHOSHMASHRAB

I, **SHAHAB KHOSHMASHRAB**, declare as follows:

1. I am presently employed by the California Energy Commission in the **ENGINEERING OFFICE** of the Facilities Siting Division as a **MECHANICAL ENGINEER**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I participated in the preparation of the staff testimony on **Power Plant Efficiency** for the **TID Almond 2 Power Plant** based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/29/2010 Signed: [signature]

At: Sacramento, California

DECLARATION OF
LAIPING NG

I, Laiping Ng declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting, Transmission & Environmental Protection Division as an Associate Electrical Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on Transmission System Engineering, for the TID Almond 2 Power Plant based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: Laiping Ng Signed: 7/20/2010

At: Sacramento, California

DECLARATION OF
Mark Hesters

I, Mark Hesters, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission and Environmental Protection Division, as a Senior Electrical Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on the **Transmission System Engineering** for the **Almond 2 Power Plant** (09-AFC-2) based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 4/20/2010 Signed: ______________________

At: Sacramento, California

DECLARATION OF
Suzanne L. Phinney, D.Env.

I, Suzanne L. Phinney, declare as follows:

1. I am presently employed by Aspen Environmental Group, consultant to the California Energy Commission's Facilities Siting Office of the Systems Assessments and Facilities Siting Division as a Senior Associate.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on Alternatives for the Almond Two Power Plant Licensing Case Project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: February 2, 2010 Signed: Suzanne L Phinney

At: Sacramento, California

DECLARATION OF
Chris Davis

I, Chris Davis, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission and Environmental Protection Division, as a Compliance Project Manager.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on the **General Conditions Including Compliance Monitoring and Closure Plan** for the **Almond II Power Plant** project (09-AFC-2) based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 19, 2010 Signed: Chris Davis

At: Sacramento, California

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE TID ALMOND 2 *POWER PLANT PROJECT*

Docket No. 09-AFC-2

PROOF OF SERVICE
(Revised 7/30/10)

APPLICANT
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*indicates change

DECLARATION OF SERVICE

I, Sabrina Savala, declare that on September 27, 2010, I served and filed copies of the attached Supplement to the Revised Staff Assessment, dated September 27, 2010. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: [http://www.energy.ca.gov/sitingcases/almond].

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

x____ sent electronically to all email addresses on the Proof of Service list;

_____ by personal delivery;

x___ by delivering on this date, for mailing with the United States Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

_____ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (*preferred method*);

OR

_____ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-2
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Original Signed by: _______________
Sabrina Savala