STOEL RIVES LLP
ATTORNEYS AT LAW

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06-AFC-5
DATE OCT 0 3 2007
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KIMBERLY HELLWIG
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October 3, 2007

BY HAND DELIVERY

Dr. James W. Reede, Jr.
Project Manager
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Re: Panoche Energy Center (06-AFC-5)

Dear Dr. Reede:

Please find enclosed for docketing a copy of the exhibits referenced in Panoche Energy Center, LLC's ("Panoche") Prehearing Conference Statement ("Statement"). Binders containing these exhibits were provided to the Commissioners and Staff at the Prehearing Conference held on October 2, 2007. Although not identified in Panoche's Statement filed September 28, 2007, we have included in the binders testimony by Panoche's witnesses related to Water Resources. As such, we have updated the indices to reflect the inclusion of the testimony as exhibits. A CD-Rom containing an electronic copy of these exhibits is also provided pursuant to your request.

Should you have any questions or will require any additional information, please do not hesitate to contact me at 916.447.0700.

Very truly yours,

Kimberly Hellwig
Paralegal

KJH:htn
Enclosures.
cc: Commissioner Jeffrey D. Byron, California Energy Commission
Commissioner James D. Boyd, California Energy Commission
Paul Kramer, Jr., Hearing Officer, California Energy Commission

Gloria Smith, Esq., Adams Broadwell Joseph & Cardozo
Mr. Gary Chandler, Panoche Energy Center, LLC
Allan Thompson, Esq., Law Office of Allan Thompson
John A. McKinsey, Esq., Stoel Rives LLP

PANOCHE ENERGY CENTER LLC'S EXHIBITS FOR EVIDENTIARY HEARING

PREHEARING CONFERENCE
OCTOBER 2, 2007

EVIDENTIARY HEARING
OCTOBER 10, 2007

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, HEARING ROOM A
SACRAMENTO, CA 95814

APPLICATION FOR CERTIFICATION (06-AFC-5)

PANOCHE ENERGY CENTER, LLC
EXHIBIT LIST

The following exhibits and declarations will be presented as indicated in Section I of Applicant's Prehearing Conference Statement.

Exhibit #	Description	Witness
1.	Panoche Energy Center, LLC's Application for Certification, Volumes I and II, August 2, 2006	Various
2.	Data Adequacy Responses, November 6, 2006	Various
3.	Responses to Staff's Data Requests, Set 1, January 9, 2007	Various
4.	Revised Figure 5.5-5, February 14, 2007	Jason Moore
5.	Responses to Staff's Data Requests, Set 2, March 1, 2007	Various
6.	Revised Data Request Response 26, April 23, 2007	John Lague
7.	Fresno County Site Plan Approval, March 26, 2007	David Jenkins
8.	Fresno County Board of Supervisors Resolution on Williamson Act Cancellation , May 9, 2007	David Jenkins
9.	Panoche Energy Center Comments to Staff's Preliminary Staff Assessment, July 26, 2007	Maggie Fitzgerald
10.	Fresno County General Plan Conformity Letter, August 8, 2007	David Jenkins
11.	Biological Opinion, August 21, 2007	Maggie Fitzgerald
12.	San Joaquin Valley Air Pollution Control District's Preliminary Determination of Compliance, May 4, 2007	David Jenkins
13.	San Joaquin Valley Air Pollution Control District's Final Determination of Compliance, July 13, 2007	David Jenkins
14.	Declaration of Noel Casil	Noel Casil
15.	Declaration of Lanny Fisk	Lanny Fisk
16.	Declaration of Brian Hatoff	Brian Hatoff
17.	Declaration of Lincoln Hulse	Lincoln Hulse
18.	Declaration of David Jenkins	David Jenkins
19.	Declaration of Michael King	Michael King
20.	Declaration of John Lague	John Lague
21.	Declaration of Angela Leiba	Angela Leiba
22.	Declaration of Ron Reeves	Ron Reeves
23.	Declaration of Stuart St. Clair	Stuart St. Clair
24.	Declaration of Eric Vonberg	Eric Vonberg
25.	Declaration of Tricia Winterbauer	Tricia Winterbauer
26.	Declaration of Jennifer Wu	Jennifer Wu

The following exhibits will be presented by witnesses at the October 10, 2007 Evidentiary Hearing.

Exhibit #	Description	Witness
27.	Technical Memorandum, March 2, 2007 *Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives*	Maggie Fitzgerald
28.	Technical Memorandum, March 23, 2007 *Supplemental Discussion of Water Supply and Wastewater Discharge Alternatives*	Maggie Fitzgerald
29.	Technical Memorandum, April 24, 2007 *Water Quality Evaluation*	Maggie Fitzgerald
30.	Letter to Dr. Reede, July 27, 2007	Gary Chandler
31.	State Water Resources Control Board Resolution 75-58	Steve Ottemoeller
32.	2003 California Energy Commission, Integrated Energy Policy Report	Steve Ottemoeller
33.	Water Balance – Lower Aquifer (2 pages)	Steve Garrett
34.	GE LMS 100 Representation	Steve Garrett
35.	Lime and Soda Ash Softening System	Steve Garrett
36.	Geologic Cross-Section	Jason Moore
37.	Groundwater Levels	Jason Moore
38.	Declaration of Maggie Fitzgerald	Maggie Fitzgerald
39.	Declaration of Jeff Fuller	Jeff Fuller
40.	Prepared Direct Testimony of Gary Chandler	Gary Chandler
41.	Prepared Direct Testimony of Maggie Fitzgerald	Maggie Fitzgerald
42.	Prepared Direct Testimony of Charles Fritz	Charles Fritz
43.	Prepared Direct Testimony of Stephen Garrett	Stephen Garrett
44.	Prepared Direct Testimony of Joseph Gruemmer	Joseph Gruemmer
45.	Prepared Direct Testimony of Jason Moore	Jason Moore
46.	Prepared Direct Testimony of Stephen Ottemoeller	Stephen Ottemoeller

Panoche Energy Center, LLC
Exhibit List Directory

The following Exhibits are in separate binders due to the voluminous nature of each Exhibit.

Exhibit #	Description
1	Panoche Energy Center, LLC's Application for Certification (2 Binders)
2	Data Adequacy Responses (1 Binder)
3	Responses to Staff's Data Requests, Set 1 (1 Binder)
5	Responses to Staff's Data Requests, Set 2 (1 Binder)
9	Panoche Energy Center Comments to Staff's PSA (1 Binder)
12	San Joaquin Valley Air Pollution Control District's Preliminary Determination of Compliance (Redwell)
13	San Joaquin Valley Air Pollution Control District's Final Determination of Compliance (Redwell)

The following Exhibits are contained in the binder entitled
"PANOCHE ENERGY CENTER, LLC – EXHIBITS"

Exhibit #	Description
4	Revised Figure 5.5-5
6	Revised Data Request Response 26
7	Fresno County Site Plan Approval
8	Fresno County Board of Supervisors Resolution on Williamson Act Cancellation
10	Fresno County General Plan Conformity Letter
11	Biological Opinion
14	Declaration of Noel Casil
15	Declaration of Lanny Fisk
16	Declaration of Brian Hatoff
17	Declaration of Lincoln Hulse
18	Declaration of David Jenkins
19	Declaration of Michael King
20	Declaration of John Lague
21	Declaration of Angela Leiba
22	This Exhibit Has Been Removed and Will Not Be Introduced
23	Declaration of Stuart St. Clair
24	Declaration of Eric Vonberg
25	Declaration of Tricia Winterbauer
26	Declaration of Jennifer Wu
27	Technical Memorandum
28	Technical Memorandum
29	Technical Memorandum
30	Letter to Dr. Reede
31	State Water Resources Control Board Resolution 75-58

Panoche Energy Center, LLC
Exhibit List Directory

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32	2003 California Energy Commission, Integrated Energy Policy Report
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43	Prepared Direct Testimony of Stephen Garrett
44	Prepared Direct Testimony of Joseph Gruemmer
45	Prepared Direct Testimony of Jason Moore
46	Prepared Direct Testimony of Stephen Ottemoeller

SLIP SHEET - EXHIBIT #1

PANOCHE ENERGY CENTER, LLC'S APPLICATION FOR CERTIFICATION (2 BINDERS)

SLIP SHEET - EXHIBIT #2

DATA ADEQUACY RESPONSES
NOVEMBER 6, 2006
(1 BINDER)

3

SLIP SHEET - EXHIBIT #3

RESPONSES TO DATA REQUESTS, SET 1
JANUARY 9, 2007
(1 BINDER)

4

URS

February 14, 2007

James W. Reede, Jr., Ed.D.
Energy Facility Siting Project Manager
California Energy Commission
1516 - 9th Street
Sacramento, CA 95814

RE: Revised Panoche Energy Center Power Plant Project (06-AFC-5) AFC Figure 5.5-5, Daily and Annual Water Flows

Dear Dr. Reede:

Please find the enclosed 75 hard copies of the revised Panoche Energy Center Application for Certification Figure 5.5-5, Daily and Annual Water Flows. This table is located on page 5.5-8 of the AFC. Please advise your staff to replace the original page 5.5-7 & 5.5-8 with a copy of the enclosed revised page (it is 3-hole punched and double sided).

Please note that the electronic copy (pdf) of the replacement page (page 5.5-8) was e-mailed to you.

If you have any questions or concerns please do not hesitate to call me at 714-648-2759.

Sincerely,

Margaret M. Fitzgerald
Program Manager

URS Corporation
2020 East First Street. Suite 400
Santa Ana, California 92705
Tel: 7146.835.6886
Fax: 714.433 7701

TABLE 5.5-5
DAILY AND ANNUAL WATER FLOWS

	Maximum Daily (1000's gal/day)	Average Daily (1000's gal/day)	Average Annual (Acre-ft/year)
Production Well Supply			
Cooling Tower Makeup	1,647	1,238	793
Demineralizer System	534	511	328
Evap Cooler Makeup	62	14	9
Plant Service Water	7	7	5
Total Process Water	2,250	1,770	1,135
Wastewater Injection			
Cooling Tower Blowdown	514	388	248
RO System Rejects	133	128	82
Evap Cooler Blowdown	31	7	4
Plant Drains	14	14	9
Intercooler Condensation	48	3	2
Total	740	540	345
Water Well (Safety use only)	0.375	0.250	0.280
Septic System (Sanitary drains only)	0.375	0.250	0.280

Notes:
The maximum daily use is based on 24 hours of full load operation during the design hottest day (114°F day/80°F night).
The average daily use is 24 hours of the average of the full load use at the average monthly temperatures for every month.
The average annual use is based on 5,000 hours/year at the average daily rate, corresponding to the maximum plant capacity factor of 57 percent.

5.5.2.1 Alternative Water Supplies

Following is a summary of the alternative water supplies that are discussed in greater detail in the Alternatives presented in Section 4 of this document:

- Surface Water – Water present in lakes, streams and rivers.
- State Water Project – California Aqueduct located approximately 2 miles east of the project site.
- Federal CVP Water – Though structurally the same facility as the California Aqueduct, the CVP share of the joint use canal facilities is named the San Luis Canal.
- Reclaimed Water – Wastewater treatment plant effluent that has received tertiary treatment.
- Agricultural Wastewater – Drainage water from irrigation practices.

5

SLIP SHEET - EXHIBIT #5

RESPONSES TO DATA REQUESTS, SET 2
MARCH 1, 2007
(1 BINDER)

6

URS

April 23, 2007

James W. Reede, Jr., Ed.D.
Energy Facility Siting Project Manager
California Energy Commission
1516 - 9th Street
Sacramento, CA 95814

RE: Revised Response to Panoche Energy Center Round 2 Data Request #26

Dear Dr. Reede:

Panoche Energy Center, LLC herby submits its revised response to Panoche Energy Center Round 2 Data Request #26. This data request response (DRR) and associated air quality modeling were revised based on requests made by the CEC at the April 13, 2007 workshop. Please have you staff replace DRR #26 in their copy of the March 1, 2007 submittal (starts on page AQ-15 under the Supplemental Data Request Responses section) with this revised response.

Please find the enclosed 20 hard copies and 10 electronic copies (on CD) of the revised Panoche Energy Center Round 2 DRR #26. The revised air quality modeling files are included on the electronic copies.

If you have any questions or concerns please do not hesitate to call me at 714-648-2759.

Sincerely,

Margaret M. Fitzgerald
Program Manager

URS Corporation
2020 East First Street, Suite 400
Santa Ana, California 92705
Tel: 7146.835.6886
Fax: 714.433.7701

Follow-up to Data Request Responses – Round 1
January 9, 2007 Submittal

TECHNICAL AREA: AIR QUALITY

Data Request 26 Rev: Please provide the cumulative modeling analysis, including the nearby Calpeak and Wellhead Energy peaker sites as proposed in the modeling protocol, as well as all District identified cumulative sources and the recently proposed Starwood Power-Midway Peaking Project (06-AFC-10).

Response:

January 9, 2007 Submittal Response:

Contrary to PEC's prior understanding, the District stated at PEC's meeting with the District on January 4, 2007 that the District would not perform the cumulative modeling analysis because it is not required to do so. PEC is willing to provide this analysis via its consultant, but requests until January 18, 2007 in which to submit a final analysis to the CEC. This cumulative analysis will consider the significance and appropriate inclusion of emissions from facilities in the District's PAS Listing, along with those of the proposed PEC and Starwood projects.

April 23, 2007 Revised Response:

Cumulative Air Quality Modeling Analysis

As required by CEC policy, a dispersion modeling analysis has been conducted to evaluate the maximum cumulative air quality effects of the Starwood Midway facility, the Panoche Energy Center and other new sources within six miles of the Midway site, that are either under construction, newly permitted in 2006 or currently in the permitting process. In addition, CEC has determined that the two existing peaker generation plants adjacent to the Midway and Panoche facilities should be included because of their proximity. These two sites are the existing CalPeak and Wellhead peaker generation facilities. The rationale for selecting these facilities for the cumulative analysis has been explained in previous data request responses. The cumulative analysis thus included the following specific point sources:

- The two Starwood Midway Swiftpac generator sets;
- The four 100 MW simple-cycle gas turbines of the proposed PEC project;
- The two 30 MW simple-cycle gas turbines of the existing CalPeak facility, which are exhausted through a single stack; and
- The two 25 MW simple-cycle turbines which are exhausted through a single stack, and the auxiliary natural gas-fired internal combustion engine of the Wellhead peaker plant.

Stack parameters and criteria pollutant emission rates for the proposed PEC and Midway projects were obtained from their recent AFC impact analyses. Comparable data for the existing CalPeak and Wellhead facilities were supplied by SJVAPCD. Based on the fact that all of these facilities are peaking power plants, as is the Midway facility, it is possible that a situation could occur in which all four plants may be operating simultaneously at maximum capacity for short periods. Accordingly, the modeling simulations to evaluate cumulative impacts for averaging times up to 24 hour assumed maximum hourly emission rates for all sources. Model runs to evaluate annual average impacts did take into account permit limitations on the allowable annual emission or hours of operation for the respective facilities. Stack parameters and emission rates for the CalPeak, Wellhead and PEC facilities are presented in Tables 1 though 3. Midway emission rates are the same as those presented in the AFC (as modified in the responses to recent data requests) and are presented in Table 4. The highest hourly emission rates associated with turbine startup or shutdown were used for the PEC and Midway facilities in the simulations for all averaging times from 1-hour to 24 hours. The assumption of concurrent unit startups for all turbines of the two new projects (PEC and Midway) gives particularly conservative results for short-term NO2 and CO concentrations. The CalPeak and Wellhead emissions data were obtained from the SJVAPCD. The annual emission rates used in the analysis for these existing sources came from actual annual facility emissions in 2004 and 2005. The short-term emission rates for CalPeak came from the Potential to Emit values provided by SJVAPCD. The short-term emission rates used for Wellhead correspond to permit limits for non-startup/shutdown conditions.

The same five-year record of hourly meteorological input data from the Fresno-Yosemite International Airport that was used in the modeling for the Midway and PEC facilities individually was also used for the cumulative modeling.

Because of the close spatial grouping of the four power projects, basically the same receptor grid used in the Midway modeling was also used for the cumulative modeling. The minor difference is that the center point of the 25-meter receptor grid is located between the PEC facility and the Midway facility and extends out 1.5 km from that point to ensure the 25-meter grid extends at least 1 km from each facility. Downwash structures were included in both the PEC and Midway facilities. Fenceline receptors were placed around each facility fenceline with 25-meter spacing. Small dense grid receptors were placed around locations of maximum concentrations that lie outside the 25-meter

Maximum concentrations due to the combined emissions of the four existing and proposed power generation facilities were calculated and the results were added to conservative background pollutant concentrations reported in the Midway and PEC AFCs. The results are presented in Table 5. As demonstrated by these results, maximum predicted concentrations for all pollutants are below applicable ambient standards, except for PM10 and PM2.5. For these pollutants, the maximum background concentrations exceed the state and federal standards, but the maximum contributions from the four modeled facilities are very small. Based on these dispersion modeling results it is concluded that the combined off-property pollutant impacts of the Midway facility and other cumulative sources close to the Midway site will be below the state and federal ambient air quality standards. Electronic input/output files are provided to accompany these responses.

Table 1 CalPeak Power Emission Rates and Stack Parameters[1]

Pollutant	Averaging Time	Emission Rate (lb/hr)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/sec)
CO	1-, 8-hour	10.73	15.24	3.6576	644.11	36.5608
NO_2	1-hour	6.17				
	Annual	0.06				
PM_{10}	24-hour	3.24				
	Annual	0.0131				
SO_2	1-hour	1.42				
	3-hour	1.42				
	24-hour	1.42				
	Annual	0.0033				

[1] Two combustion turbines emitting from 1 stack. Emissions are max 1-hour values for both units operating at maximum load. Annual numbers are 2004 actual emissions.

Table 2a Wellhead Power Emission Rates and Stack Parameters - CTGs

Pollutant	Averaging Time	Emission Rate (lb/hr)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/sec)
CO	1-, 8-hour	24.2	9.14	1.72	727	25.4
NO_x	1-hour[1]	6.2				
	Annual[2]	0.06				
PM_{10}	24-hour	4.45				
	Annual	0.093				
SO_2	1-hour	1.92				
	3-hour	1.92				
	24-hour	1.92				
	Annual	0.004				

[1] Short-term emission rates based on non-thermal permit limits.
[2] Annual emission values are from 2005 actual emissions.

Table 2b Wellhead Power Emission Rates and Stack Parameters - Natural Gas Fired Engine

Pollutant	Averaging Time	Emission Rate (lb/hr)[1]	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/sec)
CO	1-, 8-hour	4.13	6.1	0.15	888.71	38.29
NO_x	1-hour	0.0521				
	Annual	0.0521				
PM_{10}	24-hour	0.0514				
	Annual	0.0514				
SO_2	1-hour	0.0075				
	3-hour	0.0075				
	24-hour	0.0075				
	Annual	0.0075				

[1] Short-term emission rate is based on allowable emission factors in g/hp-hr times 329 horsepower, i.e., maximum hourly emission rates. Annual emission rates are maximum values allowed by the permit

Table 3a PEC CTG Emission Rates and Stack Parameters – Per CTG

Pollutant	Averaging Time	Emission Rate (lb/hr)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/sec)
CO	1-, 8-hour	59.2	27.43	4.115	692.6	31.535
NO_x	1-hour	26.31				
	Annual	5.53				
PM_{10}	24-hour	6				
	Annual	3.42				
SO_2	1-hour	1.9				
	3-hour	1.9				
	24-hour	1.9				
	Annual	1.09				

Table 3b PEC Firepump Emission Rates and Stack Parameters

Pollutant	Averaging Time	Emission Rate (lb/hr)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/sec)
CO	1-, 8-hour	0.23	5.182	0.154	739.8	31.298
NO_x	1-hour	1.38				
	Annual	0.0082				
PM_{10}	24-hour	0.0022				
	Annual	3.14E-04				
SO_2	1-hour	0.0023				
	3-hour	0.0023				
	24-hour	0.0023				
	Annual	1.34E-05				

Table 3c PEC Cooling Tower Emission Rates and Stack Parameters – Per Cell

Pollutant	Averaging Time	Emission Rate (lb/hr)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/sec)
CO	1-, 8-hour		12.8	6.71	310.9	6.1
NO_x	1-hour					
	Annual					
PM_{10}	24-hour	0.35				
	Annual	0.2				
SO_2	1-hour					
	3-hour					
	24-hour					
	Annual					

Table 4 Midway CTG Emission Rates and Stack Parameters – Per Swiftpac

Pollutant	Averaging Time	Emission Rate (lb/hr)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/sec)
CO	1-, 8-hour	9.26	15.24	4.572	744.26	23.465
NO_x	1-hour	3.21				
	Annual	1.28				
PM_{10}	24-hour	1.85				
	Annual	0.84				
SO_2	1-hour	0.44				
	3-hour	0.44				
	24-hour	0.44				
	Annual	0.13				

Table 5 ISCST3 Cumulative Impact Modeling Results

Pollutant	Averaging Period	Maximum Modeled Impact (μg/m³)	PSD Significant Impact Level (μg/m³)	Background (μg/m³)	Maximum Total Predicted Concentration (μg/m³)	Most Stringent AAQS (μg/m³)	UTM Coordinates East (m)	UTM Coordinates North (m)
Cumulative Impacts								
CO	1 hour	173.81	2,000	7,705	7,879	23,000	716,739	4,058,856
	8 hour	81.47	500	5,156	5,237	10,000	716,664	4,048,906
NO_2	1 hour	91.70	NA	169.2	260.9	470	715,864	4,058,606
	Annual	0.13	1	42.0	42.1	100	707,675	4,056,950
PM_{10}	24 hour	3.30	5	193.0	196.3	50	707,700	4,056,825
	Annual	0.14	1	43.0	43.1	20	716,689	4,058,881
$PM_{2.5}$	24 hour	3.30	NA	110.0	113.3	65	707,700	4,056,825
	Annual	0.14	NA	21.6	21.7	12	716,689	4,058,881
SO_2	1 hour	4.22	NA	23.6	27.8	655	710,925	4,053,600
	3 hour	3.07	25	15.6	18.7	1,300	711,100	4,053,400
	24 hour	1.04	5	10.5	11.5	105	707,700	4,056,825
	Annual	0.023	1	5.3	5.3	80	707,675	4,056,950

Notes:
μg/m³ = micrograms per cubic meter
CO = carbon monoxide
ISCST3 = USEPA Industrial Source Complex model, Version 02035
m = meters
NA = Not applicable
NAAQS = Most stringent ambient air quality standard for the averaging period
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than or equal to 10 microns in diameter
$PM_{2.5}$ = particulate matter less than or equal to 2.5 microns in diameter. All PM emissions during operation assumed to be $PM_{2.5}$
PSD = Prevention of Significant Deterioration
SO_2 = sulfur dioxide
UTM = Universal Transverse Mercator

7

County of Fresno

DEPARTMENT OF PUBLIC WORKS AND PLANNING
ALAN WEAVER, DIRECTOR

DOCKET
06-AFC-5
DATE MAR 2 6 2007
RECD. APR 1 0 2007

March 26, 2007

W. David Jenkins
1293 E. Jessup Way
Mooresville, IN 46158

To Whom It May Concern:

SUBJECT: SITE PLAN REVIEW NO. 7586

Site Address:	43883 W. Panoche Road
APN:	027-060-78S
Zoning District:	AE-20 (Exclusive Agricultural)
Use Approved:	Allow a 400MW Peaking Power Plant
Legal Description of Site:	See attached description

The Department of Public Works and Planning has reviewed your application and determined that the required findings can be made and hereby approves Site Plan Review No. 7586 subject to the following conditions.

CONDITIONS OF APPROVAL

The required improvements are listed below and on the approved plans. An inspection is required prior to the issuance of a Certificate of Occupancy to assure compliance with these conditions and the approved Site Plan. Please call (559) 262-4029, Fresno County Department of Public Works and Planning, Building and Safety Section, to arrange for this inspection when required improvements are completed.

PROOF OF SERVICE (REVISED 3/16/07) FILED WITH ORIGINAL MAILED FROM SACRAMENTO ON 4/10/07

Prior to the issuance of a Building Permit Required Development Clearances shall be completed/satisfied.

I. REQUIRED DEVELOPMENT CLEARANCES

A. All driveways and parking areas to be used by motor vehicles shall be designed by an architect or civil engineer in accordance with Fresno County Standards. Engineered plans for the construction, including a complete listing of materials, costs, and quantities in place, shall be submitted to this Department for approval. A Plan Check Fee, based upon construction costs, will be collected with the submittal of the Grading and Drainage Plan. The engineer who prepares the plan shall certify to this Department that the facilities have been constructed in accordance with approved plans and specifications.

B. Storm water due to this development shall be retained on the property being developed in accordance with Fresno County Improvement Standards.

C. When provisions are made to retain all runoff from this development within a drainage pond(s) or other facility acceptable to the Director of the Department of Public Works and Planning, the storage capacity shall be based on the formula: Storage = (.50) CA.

D. A Grading and Drainage Plan shall be prepared by a Registered Civil Engineer and submitted to the Department of Public Works and Planning, in accordance with Section 6731 of the California Business and Professions Code. The Plan shall have an Engineer's Certificate indicating that the grading and drainage will have no adverse effect on the adjoining properties. Contact the Drainage and Grading Engineer for Drainage Plan requirements at (559) 262-4167.

E. The design of the on-site fire protection water system, including, but not limited to the location and number of fire hydrants, and the size of the water mains, shall be submitted to the Fresno County Fire Protection District for review (Their comments have been attached.). A plan must be submitted to this Department from the Fire District with their recommendations/approval. Contact Fire Protection Planning at (559) 485-7500 for an appointment.

F. The Mendota Unified School District, in which you are proposing construction, has adopted a resolution requiring the payment of a Development Impact Fee. The County, in accordance with State law, which authorizes the fee, will not issue a building permit without certification from the school district that the fee has been paid. An official certification form will be provided by the County when application is made for a building permit.

G. A permit is required to be obtained from the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). Contact the District at (559) 230-6000 for permitting requirements. A copy of the Authority to Construct shall be submitted to this Department.

H. All Williamson Act requirements shall be satisfied.

Prior to the Certificate of Occupancy being granted all items listed below shall be completed/satisfied.

II. <u>OFF-SITE IMPROVEMENTS</u>

A. The necessary permits for off-site improvements shall be obtained from the Fresno County Department of Public Works and Planning, Road Maintenance and Operations Division, and shall be installed in accordance with Fresno County Improvement Standards.

B. The developer is responsible for relocating those utilities within the road right-of-way(s) to the correct alignment and grade affected by the developer's improvements.

C. An asphalt concrete driveway approach 24 to 35 feet in width shall be constructed along Panoche Road. The driveway shall intersect the Road at a 90 degree angle.

III. <u>ON-SITE IMPROVEMENTS</u>

A. The parking, circulation, and loading areas shall be graded and surfaced as noted on the approved plan. One parking space shall be provided for the physically disabled in accordance with the attached sheet. The space shall be located on the shortest possible route to an accessible entrance and shall be concrete or asphalt concrete paved. The required parking for the physically disabled shall be shown on the Grading and Drainage Plan.

B. The driveway shall be graded and asphalt concrete paved a minimum width of 24 feet for the first 100 feet South of the ultimate road right-of-way. The driveway shall intersect the Road at a 90 degree angle.

C. Active storage areas, truck parking, and circulation areas shall be treated with a dust palliative and repeated as necessary to prevent the creation of dust by vehicles.

D. All outdoor lighting shall be hooded and directed so as not to shine toward public roads or the surrounding properties.

E. Any access gate shall be setback a minimum of 20 feet (or the length of the longest vehicle to initially enter the site) from the edge of the ultimate road right-of-way.

IV. <u>MISCELLANEOUS</u>

A. Permits for structural, electrical, and plumbing work shall be obtained from the Department of Public Works and Planning, Permits Counter, prior to any construction.

B. All proposed signs shall be submitted to the Department of Public Works and Planning, Permits Counter to verify compliance with the Zoning Ordinance.

C. Vehicular access to this development shall be limited to the driveway approach shown on the approved plan.

D. Fire protection improvements shall be in place and inspected by the Fresno County Fire Protection District prior to occupancy. Contact the District at (559) 485-7500 to arrange for an inspection. Allow 14 to 21 days for the District to complete the inspection.

E. A Hazardous Materials Business Plan or Business Plan Exemption shall be completed and submitted to the Fresno County Department of Community Health, Environmental Health System. Contact the Certified Unified Program Agency (CUPA) at (559) 445-3271 for information. A letter shall be submitted from CUPA stating that the Business Plan or Exemption has been submitted.

F. The Civil Engineer who prepares the on-site improvement plans shall inspect construction of the facilities and shall certify to the Department of Public Works and Planning that the work conforms with approved plans and specifications.

G. A 45 degree (45°) corner cut-off of no obstruction to visibility shall be maintained. (See typical corner cut-off drawing.)

H. A copy of the Permit to Operate issued by the San Joaquin Valley Unified Air Pollution Control District shall be submitted to this Department.

I. Waste water shall be disposed of in accordance with California Regional Water Quality Control Board requirements. Documentation shall be provided to this Department showing that this project is in compliance with Board requirements.

V. <u>NOTES</u>

A. Specific industrial activities, including manufacturing, transportation, waste handling facilities and others which might generate contaminated runoff, must secure Storm Water Discharge Permits from the State Water Resources Control Board in compliance with the NPDES Regulations promulgated by the U.S.E.P.A. (CFR Parts 122-124, Nov. 1990). If the applicant determines that a NPDES Permit is required for operations of the proposed facility, a State General Permit Notice of Intent must be filed with the State Water Resources Control Board. Copies of the State General Permit and Notice of Intent are available at the Fresno Metropolitan Flood Control District. For more information on procedures, contact the California State Water Resources Control Board, Division of Water Quality, Attention: Storm Water Permit Unit, P.O. Box 1977, Sacramento, CA 95812-1977 or call (916) 341-5536 for an individual to address your concerns.

B. Construction activities, including grading, clearing, grubbing, filling, excavation, development or redevelopment of land that would result in a disturbance of one (1) acre or more of the total land area, must secure a Storm Water Discharge Permit in compliance with the U.S.E.P.A.'s NPDES Regulations (CFR Parts 122-124, Nov. 1990). The Permit must be secured by filing a Notice of Intent for the State General Permit for Construction Activity with the State Water Resources Control Board. Copies of the State General Permit and Notice of Intent are available at the Fresno Metropolitan Flood Control District. For more information or procedures, contact the California State Water Resources Control Board, Division of Water Quality, Attention: Storm Water Permit Unit, P.O. Box 1977, Sacramento, CA 95812-1977 or call (916) 341-5536 for an individual to address your concerns.

C. The proposed development shall implement all applicable Best Management Practices (BMPs) presented in the Construction Site and Post-Construction Storm Water Quality Management Guidelines, available at the Fresno Metropolitan Flood Control District office, to reduce the release of pollutants in storm water runoff to the maximum extent practicable. Contact the District at (559) 456-3292 for information.

D. All hazardous waste shall be handled in accordance with the requirements set forth in the California Health and Safety Code, Chapter 6.5. This chapter discusses proper labeling

E. If the use of this property should ever change, the owner or operator is obligated to verify that the new use would be allowed by all applicable building codes and ordinances of Fresno County. Contact the Fresno County Department of Public Works and Planning, Permits Counter at (559) 262-4302 for information on applicable codes and ordinances.

F. All hazardous waste shall be handled in accordance with the requirements set forth in the California Health and Safety Code, Chapter 6.5. This chapter discusses proper labeling, storage, and handling of hazardous wastes.

G. Should a water well be drilled to serve the administration and control buildings, a Permit to Construct a Water Well shall be obtained from the Fresno County Department of Community Health, Environmental Health System. Contact Ed Yamamoto at (559) 445-3357 for information.

H. The project description indicates the use of aqueous ammonia. Based upon the information contained in the operational statement, this facility will have to comply with the California Accidental Release Prevention (Cal-ARP) Program (Title 19, California Code of Regulations Section 2745.1(e)). A Risk Management Plan shall be submitted to the local Certified Unified Program Agency (CUPA) prior to the date in which the regulated substance (ammonia) is first present in the process above the listed threshold quantity of 500 pounds. Contact the CUPA at (559) 445-3271 for information.

I. Fresno County Ordinances require that sanitary facilities shall be installed in accordance with requirements of the Fresno County Department of Public Works and Planning.

J. Required site improvements may be bonded in accordance with the provisions of Section 874-C-2 of the Fresno County Zoning Ordinance.

K. This Site Plan Review approval shall expire in two years from the date of approval unless substantial development has commenced.

This approval is final, unless appealed to the Fresno County Planning Commission. In this event, you must submit a fee of $482.50 and file a written appeal setting forth your reasons for such appeal to the Commission. Such appeal shall be filed with the Director of the Department of Public Works and Planning within 15 days after the mailing of this decision and shall be addressed to:

Department of Public Works and Planning
Development Services Division
Attention: Robin Tani

2220 Tulare Street, Sixth Floor
Fresno, CA 93721

If you have any questions, please contact me at (559) 262-4215.

Very truly yours,

Robin Tani, Senior Planner
Development Services Division

G:\4360Devs&Pln\BLD_SFTY\Zoning\S.P.R\SPR Approvals\7586rev.doc

c: Fresno County Department of Community Health, Environmental Health System
Fresno County Fire Protection District; 210 S. Academy Ave.; Sanger, CA 93657
Gary R. Chandler; 2542 Singletree Lane; S. Jordan, UT 84095

Enclosure

**LEGAL DESCRIPTION
PREMISES BOUNDARY EASEMENT
"PROPOSED PANOCHE ENERGY CENTER"
PORTION OF
ASSESSOR'S PARCEL 027-060-78S
VICINITY OF FIREBAUGH,
FRESNO COUNTY, CALIFORNIA**

October 9, 2006

Being a portion of real property in the Southwest Quarter of Section 5 Township 15 South, Range 13 East, Mount Diablo Base and Meridian, according to the official plat thereof lying Southerly of Panoche Road, being a portion of that certain real property described in a document dated June 13, 1978 to Robert Hansen, Trustee under the Sharla M. Baker Trust as Instrument No. 89-106620 Official Records, County of Fresno, vicinity of Firebaugh, California more particularly described as follows:

COMMENCING at the Southwest Corner of said Section 5 at a found 2" iron pipe thence along the West line of said Section 5 being the Southwest Quarter thereof North 01° 34' 29" East 902.88 feet; thence leaving the West line of said Section 5 through the interior of said Southwest Quarter of Section 5 the following seven (7) courses: South 89° 10' 03" East 39.95 feet to the **POINT OF BEGINNING** of the herein described real property; North 00° 49' 57 " East 522.11 feet; South 89° 10' 03" East 1001.11 feet; South 00° 49' 57 " West 690.97 feet; North 89° 10' 03" West 212.94 feet; North 00° 49' 57" East 168.86 feet; North 89 10' 03" West 788.17 feet to the **POINT OF BEGINNING.**

Containing 558,646 square feet of land (12.82 acres), more or less.

This description is based on record information. The Basis of Bearings are NAD 1983, Epoch 2004.50, California Coordinate System, Zone 4 and are based upon a GPS Survey constrained to NGS monuments: AC6117 (HPGN D CA 06 NC) survey disk in bridge abutment and GU4142 (Z 1444) stainless steel rod.

FRESNO COUNTY

FIRE PROTECTION DISTRICT

March 6, 2007

Richard Perkins, Planner
County of Fresno
Fresno County Public Works & Development Services
2220 Tulare Street, Six Floor
Fresno, CA 93721

Transmitted by Email to: rperkins@co.fresno.ca.us

RE: **SPR# 7586**
Panoche Energy Center, LLC
43649 Panoche Road
Firebaugh, Ca.

Dear Richard Perkins, Planner:

The Fresno County Fire Protection District comments in regards to the above project requires compliance of the 2001 California Fire Code and the following Articles & Sections:

CALIFORNIA FIRE CODE, 903.2 **Required water supply for fire protection**
An approved water supply capable of supplying the required fire flow for fire protection shall be provided to all premises upon which facilities, buildings or portions of buildings are hereafter constructed or moved into or within the jurisdiction.

Note: When any portion of the facility or building protected is in excess of 150 feet (45 720 mm) from a water supply on a public street, as measured by an approved route around the exterior of the facility or building, on-site fire hydrants and mains capable of supplying the required fire flow shall be provided when required by the chief. See Section 903.4.
Submit water plans to the Fire Prevention Bureau for approval

CALIFORNIA FIRE CODE, 1002.1 **Portable fire extinguishers**
Portable fire extinguishers shall be in accordance with UFC Standard 10-1.
UFC Standard 10-1, 1-6.8 Extinguishers installed under conditions where they are subject to physical damage shall be protected from impact.

CALIFORNIA FIRE CODE, 902.2.2.1 **Fire Department Access - Dimensions**
Fire apparatus access roads shall have an unobstructed width of not less than 20 feet and an unobstructed vertical clearance of not less than 13 feet 6 inches.

Telephone (559) 485-7500 Ext- 113 210 South Academy Avenue, Sanger, California 93657 FAX (559) 875-7451

CALIFORNIA FIRE CODE, 902.2.2 **Obstruction & control of fire apparatus access**
The required width of a fire apparatus access shall not be obstructed in any manner, including parking of vehicles. Minimum required widths and clearances established under section 902.2.2.1 shall be maintained at all times.

CALIFORNIA FIRE CODE, 902.2.2.2 **Surface**
Fire apparatus access roads shall be designed and maintained to support the imposed loads of fire apparatus and shall be provided with a surface so as to provide all-weather driving capabilities.

CALIFORNIA FIRE CODE, 901.4.4 **Premises identification**
Approved numbers or addresses shall be provided for all new and existing buildings in such a position as to be plainly visible and legible from the street or road fronting the property.

CALIFORNIA FIRE CODE, 902.4 **Key Boxes**
When access to or within a structure or area is unduly difficult because of secured openings or where immediate access is necessary for life-saving or firefighting purposes, the chief is authorized to require a key box to be installed in an accessible location. The key box shall be of an approved type and shall contain keys to gain necessary access as required by the chief.

CALIFORNIA FIRE CODE, 1001.7.2 **Clear space around hydrants**
A 3-foot clear space shall be maintained around the circumference of the fire hydrants except as otherwise required or approved.

Submit plans for all buildings that will be Sprinkled.
Submit plans for all buildings that will be Fire Alarmed.

Please contact me at (559) 485-7500 Ext. 113, if you have any questions.

Sincerely,

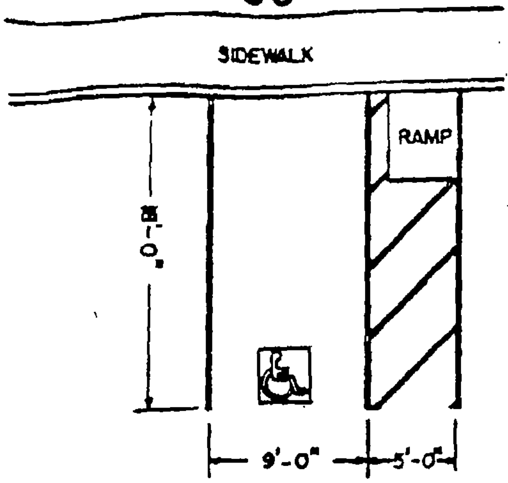
BECKY ROBERTSON, CHIEF

By: George Mavrikis-FPS-1
Fire Protection Planning

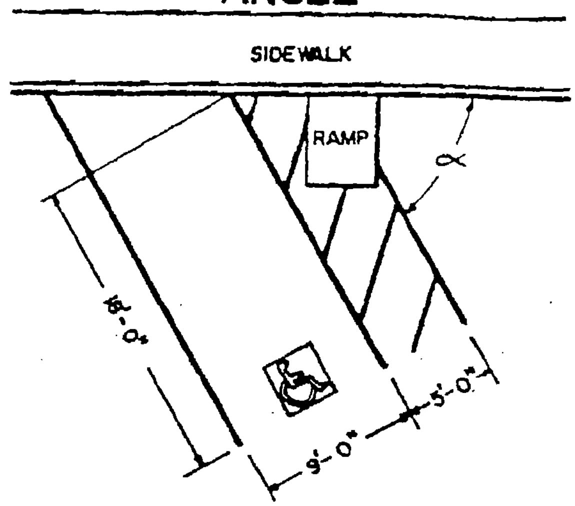
HANDICAPPED PARKING STALLS

SINGLE STALL

90°

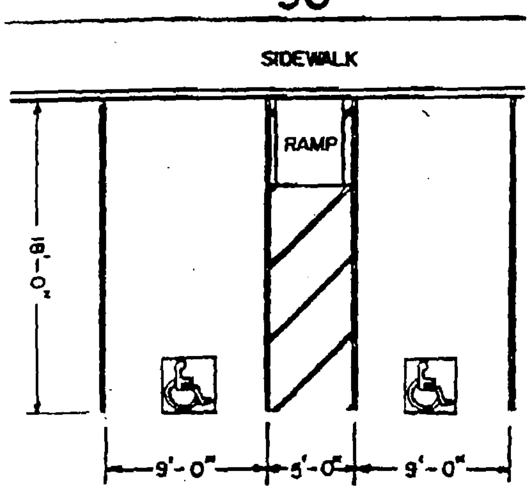


ANGLE

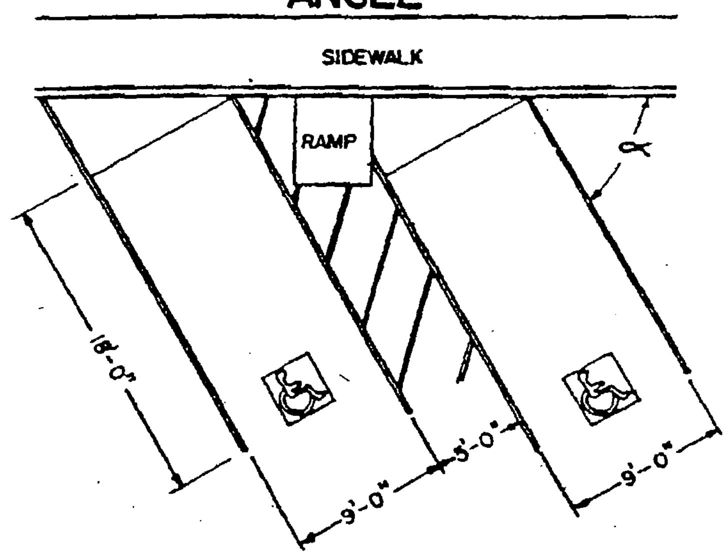


DOUBLE STALLS

90°

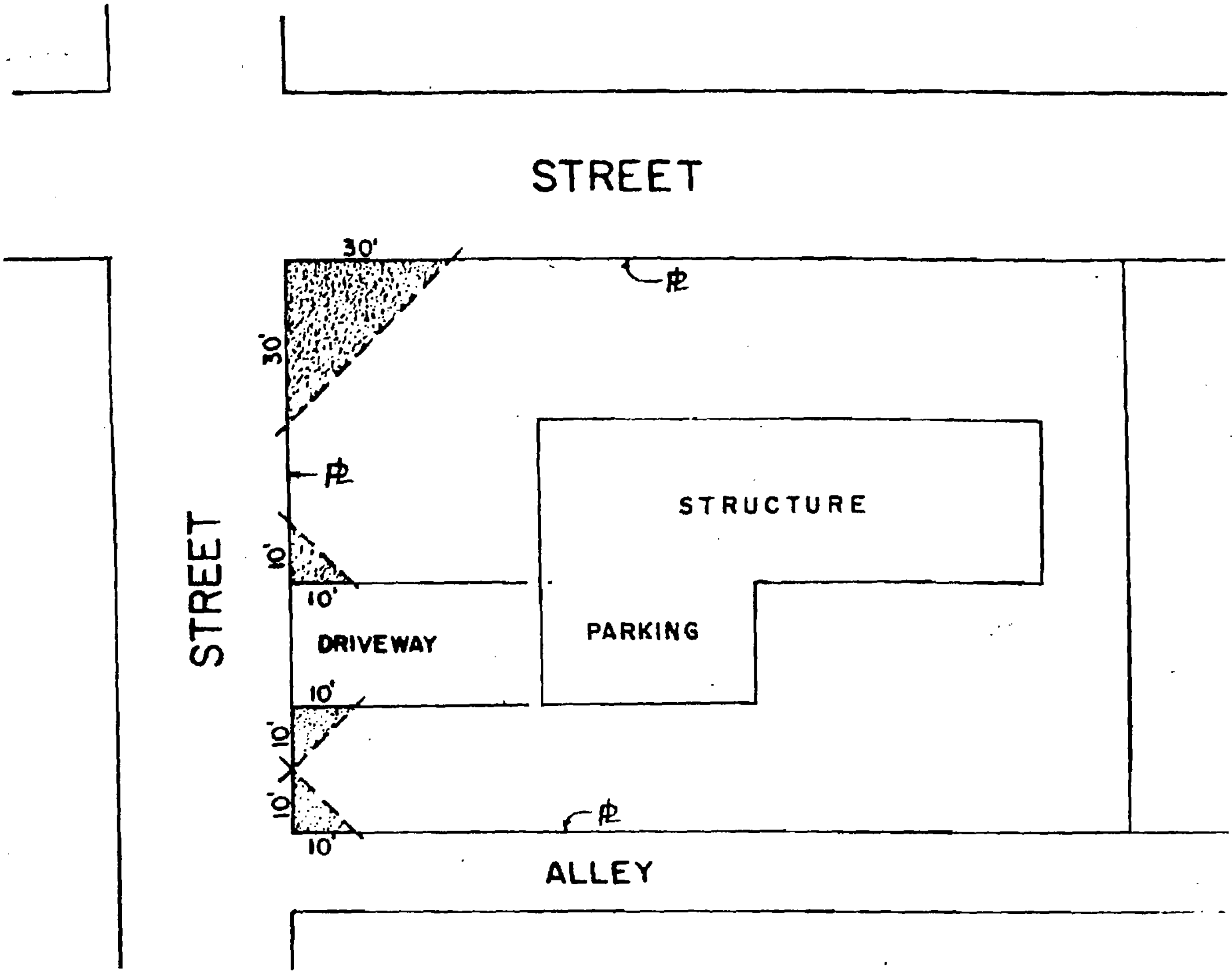


ANGLE



NOTES:

1. Dimensions shown are the allowed minimums.
2. Angle ∝ is a variable, allowed angles are: 30°, 40°, 45°, 50°, 60°, & 75°.
3. 2½' wide stripes in the loading zone shall be 3' on center.
4. The location of the ramp may vary and must comply with Fresno County Standards.
5. Sidewalks and ramp shall have a minimum width of 48".
6. The handicapped logo shall be a white symbol on a blue background.
7. A sign of not less than 70 square inches in area shall be placed on center of the interior end of the parking space at a minimum height of 80 inces from the bottom of the sign to the surface of the parking space.
8. Where applicable, the curb or the bumper stop shall be painted the same color blue as the handicapped logo.



TYPICAL CORNER CUT-OFF

(INDICATED IN GREY)

REQUIREMENTS OF THE CORNER CUT-OFF AREA

1. The branches of trees located within the corner cut-off area must be trimmed and maintained at a height of not less than seven (7) feet.

2. Bushes and shrubs must be trimmed and maintained at a height not to exceed three (3) feet. Fences, hedges, and walls shall not exceed three (3) feet in height.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

APPLICATION FOR CERTIFICATION FOR THE PANOCHE ENERGY CENTER	**Docket No. 06-AFC-5** **PROOF OF SERVICE** **(Revised 3/16/07)**

INSTRUCTIONS: All parties shall 1) send an original signed document plus 12 copies OR 2) mail one original signed copy AND e-mail the document to the web address below, AND 3) all parties shall also send a printed OR electronic copy of the documents that shall include a proof of service declaration to each of the individuals on the proof of service:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 06-AFC-5
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

APPLICANT

Gary R. Chandler
Panoche Energy Center, LLC
P.O. Box 95592
South Jordan, UT 84095-0592

APPLICANT CONSULTANTS

Maggie Fitzgerald, Program Manager
URS
2020 East First Street, Suite 400
Santa Ana, CA 92705

COUNSEL FOR APPLICANT

Allan Thompson
21 "C" Orinda Way, No. 314
Orinda, CA 94563
allanori@comcast.net

INTERESTED AGENCIES

Larry Tobias
Ca. Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630
LTobias@caiso.com

Electricity Oversight Board
770 L Street, Suite 1250
Sacramento, CA 95814
esaltmarsh@eob.ca.gov

INTERVENORS

CURE
Gloria D. Smith
Adams Broadwell Joseph & Cardozo
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080
gsmith@adamsbroadwell.com

CURE
Marc D. Joseph
Adams Broadwell Joseph & Cardozo
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080
mdjoseph@adamsbroadwell.com

ENERGY COMMISSION

JEFFREY D. BYRON
Presiding Member
jbyron@energy.state.ca.us

JAMES D. BOYD
Associate Member
jboyd@energy.state.ca.us

Paul Kramer, Jr.
Hearing Officer
pkramer@energy.state.ca.us

James Reede
Project Manager
jreede@energy.state.ca.us

Dick Ratliff
Staff Counsel
dratliff@energy.state.ca.us

Margret J. Kim
Public Adviser
pao@energy.state.ca.us

DECLARATION OF SERVICE

I, Diana Tercero, declare that on April 10, 2007, I deposited copies of the attached Site Plan Review No. 7586 Regarding the Proposed 400-megawatt (MW) Simple-cycle Power Plant for the Panoche Energy Center project (06-AFC-5), in the United States mail at Sacramento, California with first-class postage thereon fully prepaid and addressed to those identified on the Proof of Service list above.

OR

Transmission via electronic mail was consistent with the requirements of California Code of Regulations, title 20, sections 1209, 1209.5, and 1210. All electronic copies were sent to all those identified on the Proof of Service list above.

I declare under penalty of perjury that the foregoing is true and correct.

Diana Tercero
[signature]

8

Agenda Item 19

DATE: April 24, 2007

TO: Board of Supervisors

FROM: Alan Weaver, Director
Department of Public Works and Planning

Alan Weaver

SUBJECT: Partial Cancellation of Agricultural Land Conservation Contract No. 367 (Revision No. 838)

RECOMMENDED ACTIONS:

Adopt resolution authorizing partial cancellation of Agricultural Land Conservation Contract No. 367, based on the five findings required by the Land Conservation Act of 1965 (Williamson Act); and

Authorize the Chairman to sign the Certificate of Tentative Cancellation and approve recordation of the Certificate of Cancellation at such time as all conditions included in the Certificate of Tentative Cancellation have been satisfied.

Approval of the recommended action would remove approximately 12.82 acres of prime agricultural land from contract restrictions for development of a 400-megawatt thermal power plant. The subject property is located on the south side of Panoche Road, between Interstate 5 and Fairfax Avenue, approximately 13 miles southwest of the City of Mendota. (See Location Map Exhibit 'A', Zoning Map Exhibit 'B', and Land Use Map Exhibit 'C') (45499 Panoche Road) (SUP. DIST. 1) (APN: 027-060-78s).

This item comes before your Board with a recommendation for approval by the Agricultural Land Conservation Committee subject to certain conditions.

FISCAL IMPACT:

There is no net County cost associated with the recommended actions. Property taxes would increase on the lands to be removed from ALCC No. 367. The applicant paid the County fee of $3,097.00 and is aware of the penalty that would be levied by the State Department of

ADMINISTRATIVE OFFICE REVIEW ______ Page 1 of 12
BOARD ACTION: DATE ______ APPROVED AS RECOMMENDED ______ OTHER ______

UNANIMOUS ______ ANDERSON ______ CASE ______ LARSON ______ PEREA ______ WATERSTON ______

FC-017 (eForms-0904)

Conservation. This penalty is 12½ percent of the current fair market value of the land being removed from contract as though it was free of contractual restrictions. This amount has been calculated by the Assessor's Office to be $6,375.00.

IMPACTS ON JOB CREATION:

Approval of the recommended actions should not impact the creation of jobs in Fresno County.

DISCUSSION:

In order to approve a cancellation request, the Board of Supervisors must determine that the action is consistent with the Land Conservation Act of 1965. The law requires that five findings be made. Staff analysis of the required findings is as follows:

1. *That the cancellation is for land on which Notice of Nonrenewal has been served pursuant to Section 51245 of the Government Code.*

   An executed Notice of Partial Nonrenewal for ALCC No. 367 was accepted by the County Recorder on November 6, 2006, and was assigned Document No. 2006-0236374. Nonrenewal was initiated on the entire 128 acres that comprise APN 027-060-78s.

2. *That the cancellation is not likely to result in the removal of adjacent lands from agricultural use.*

   The subject property and adjacent parcels are currently devoted to agricultural uses, with the exception of the existing PG&E substation located on a separate parcel adjacent to the northeast of the area proposed for Williamson Act cancellation. The applicant has stated that the proposed location of the thermal power plant is ideal due to the existing infrastructure installed at the existing Pacific Gas & Electric substation and by the existing high-volume natural gas lines and 230 kilovolt transmission lines located on the subject parcel. Two power generation facilities already exist next to the PG&E substation. The existing infrastructure allows for efficient interconnection, which minimizes impacts, specifically environmental impacts.

   Staff agrees that the proposed use of the property for a thermal power plant would not cause any disruption to adjacent parcels and would not result in restrictions on the use of adjacent parcels. While it is possible that adjacent land may be removed from agricultural use, for development of additional power plants, this would be due to the clustering of the necessary infrastructure for efficient interconnection with existing facilities and resources rather than the development of the proposed thermal power plant.

3. *That the cancellation is for an alternative use that is consistent with the provisions of the County General Plan.*

   The subject property is designated Agriculture in the Fresno County General Plan. The proposed alternate use of the property is development of a thermal power plant. Permitting for this use is issued through the State of California, so no land use applications would be processed by the County of Fresno during development of the thermal power plant. Nevertheless, the County's General Plan allows for development of certain non-agricultural uses in areas designated for Agriculture.

According to information provided by the applicant, the location of a power generation facility within an urban environment has the potential to impact sensitive receptors such as schools and hospitals in addition to greater land use conflicts with residences. Further, the applicant indicated that the site selection investigation that was performed looked for land that was in sufficient proximity to the infrastructure listed above. The applicant reported that no less productive agricultural lands were identified as a result of the site selection investigation. Based on the information provided by the applicant, staff believes that the proposed alternate use is consistent with the General Plan. Based on this information, this finding can be made.

4. *That the cancellation will not result in discontiguous patterns of urban development.*

   The proposed use of the property for a thermal power plant would not be considered urban development. Based on this, staff believes this finding can be made.

5. *That there is no proximate non-contracted land which is both available and suitable for the use to which it is proposed that the contracted land be put, or that development of the contracted land would provide more contiguous patterns of urban development than development of proximate non-contracted land.*

   The applicant conducted an analysis of proximate non-contracted land, to determine if any non-contracted land was both available and suitable for the proposed alternate use. The applicant stated that in order to be suitable for development, of the proposed power plant would require that the land be in close proximity to the existing PG&E substation and to high-volume natural gas lines. Parcels within three miles of the subject property were examined by the applicant, but were all either subject to Williamson Act Contract or were too distant from the existing PG&E substation and/or high-volume natural gas lines to be considered feasible alternatives to the subject property.

It has been determined that the project proposal is considered statutorily exempt from California Environmental Quality Act (CEQA), under Section 15271, Early Activities Related to Thermal Power Plants. A copy of the County's CEQA Determination memo is included as Exhibit 'D'.

<u>OTHER REVIEWING AGENCIES:</u>

As of January 1, 2001, Government Code Section 51284.1(a) requires notification to be provided by the County to the Director of the State Department of Conservation (the Director) once a cancellation application has been accepted as complete. Under Government Code Section 51284.1(c), the Director's comments are required to be considered by the Board of Supervisors before acting on the proposed cancellation. Pursuant to the Director's January 19, 2007, letter providing comments on the applicant's information related to the required findings, the Department of Conservation stated that the Board of Supervisors has a basis to find cancellation of the 12.82-acre portion of the Contract consistent with the purposes of the Williamson Act The Director's comments are attached as Exhibit 'E'.

<u>AGRICULTURAL LAND CONSERVATION COMMITTEE RECOMMENDATION:</u>

The Agricultural Land Conservation Committee (ALCC) reviews petitions for cancellation of Williamson Act contracts and provides recommendations to your Board. At its meeting of April 4, 2007, the ALCC voted unanimously to forward this request to your Board with a recommendation for approval subject to the below conditions:

1. Payment in full of the cancellation fee.

2. Unless the cancellation fee is paid or a Certificate of Cancellation of Contract is issued within one year from the date of the recording of this certificate, the cancellation fee shall be recomputed as of the date of notice by the landowner to the Board of Supervisors required by Government Code Section 51283.4.

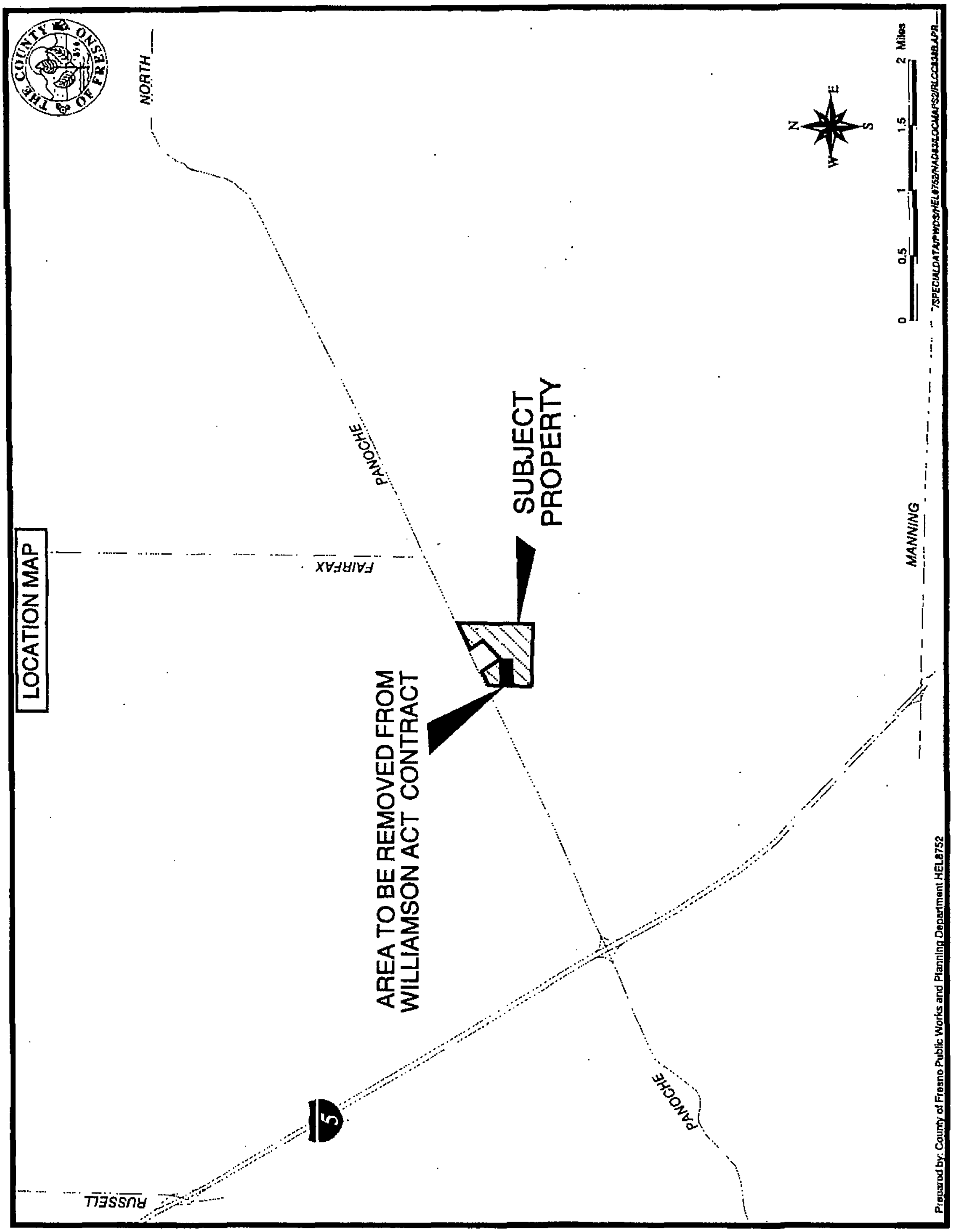
3. The landowner shall obtain all permits necessary to commence the project.

NOTICING:

All contracted landowners within one mile of the subject property, including the applicants, were noticed and notice was published as required.

JN
G:\4360Devs&Pln\ADMIN\BOARD\Board Items\2007\04-24-07\RLCC 838_PAO_AI.doc

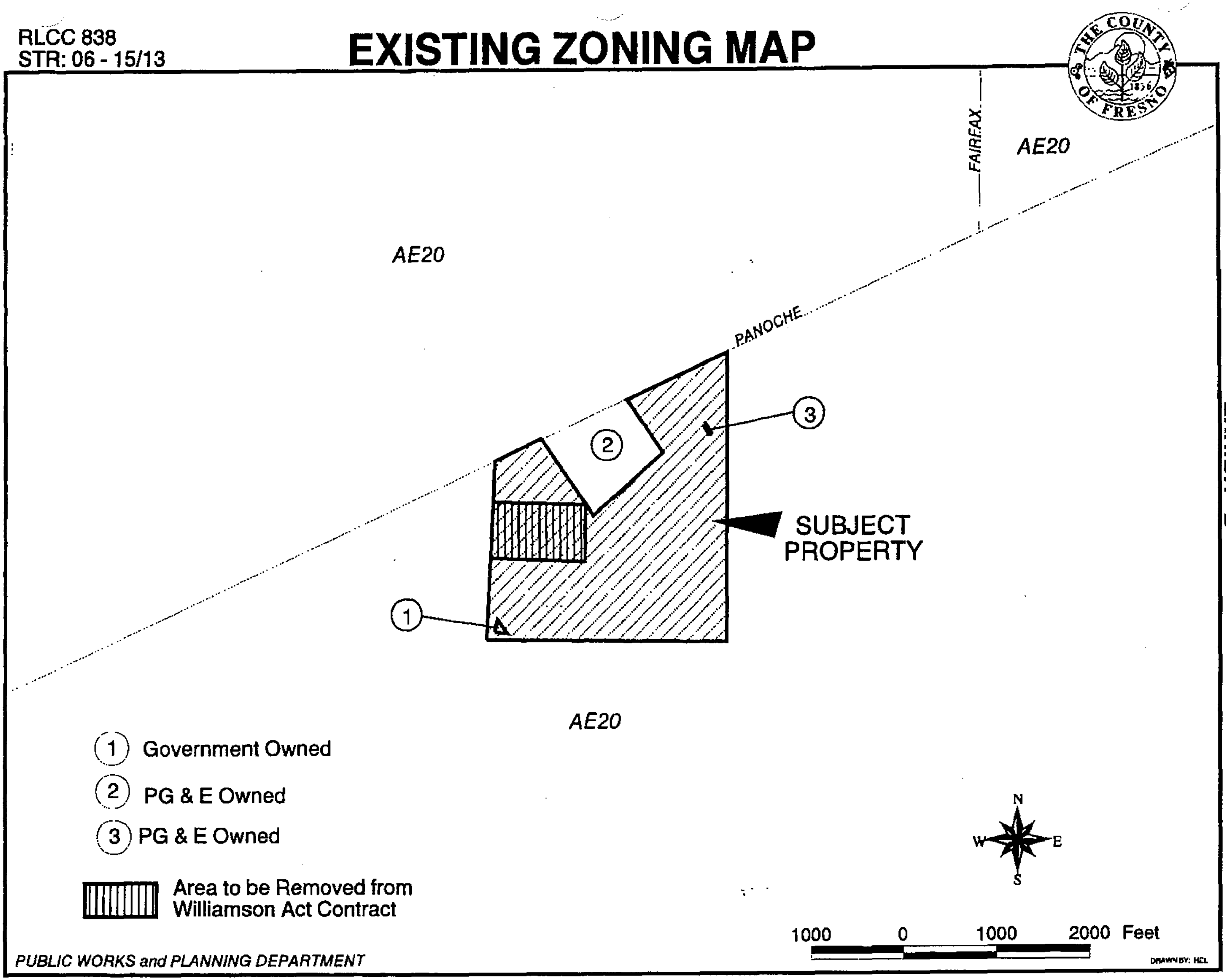
EXHIBIT 'A'


LOCATION MAP
NORTH
PANOCHE
FAIRFAX
SUBJECT PROPERTY
AREA TO BE REMOVED FROM WILLIAMSON ACT CONTRACT
MANNING
PANOCHE
5
RUSSELL
N
E
S
W
0
0.5
1
1.5
2 Miles
Prepared by: County of Fresno Public Works and Planning Department HEL8752

RLCC 838
STR: 06 - 15/13

EXISTING ZONING MAP

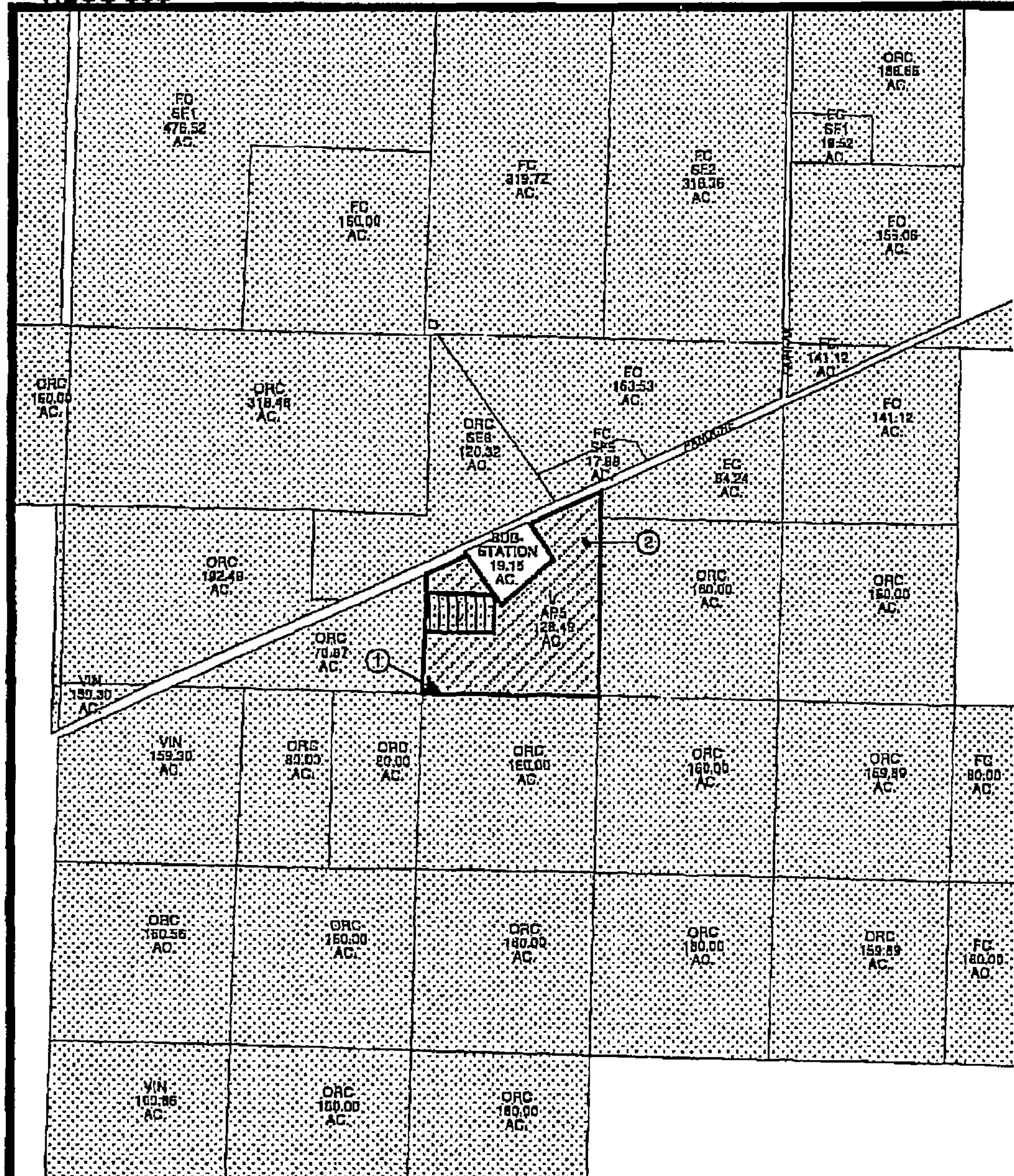
EXHIBIT 'B'



RLCC 838

EXISTING LAND USE MAP

EXHIBIT 'C'



Legend

AP1 - APARTMENT
FC - FIELD CROP
ORC - ORCHARD
SF#- SINGLE FAMILY RESIDENCE
V - VACANT
VIN - VINEYARD

Subject Property

Ag Contract Land

Area to be Removed from Ag Contract Land

1 Government Owned

2 PG&E Owned

N W E S

0.2 0 0.2 0.4 0.6 0.8 Miles

Prepared by: County of Fresno The Department of Public Works and Planning HEL8752

EXHIBIT 'D'

Inter Office Memo

DATE: March 14, 2007

TO: PAO Investments, LLC

FROM: Briza Sholars, Development Services BS

SUBJECT: CEQA Determination
Environmental Review No. 5785 (45499 Panoche Road)

Project Description:

The project proposes a partial cancellation of Williamson Act Contract No. 367 on 12.8 acres of a 128 acre parcel of land in the AE-20 (Exclusive Agriculture, 20-acre minimum lot size) Zone District to allow for future development of a thermal power plant. The project is located on the south side of Panoche Road between South Brannon Avenue and South Fairfax Avenue in an unincorporated area of Fresno County.

Determination

The proposed project is considered Statutory exempt from the California Environmental Quality Act (CEQA), under Section 15271, Early Activities Related to Thermal Power Plants. The following supports this determination:

1. The intent of Section 15271 of the CEQA Guidelines is to exempt or delay early activities related to thermal electric power plants which will be the subject of an EIR or Negative Declaration or other document or documents prepared pursuant to a regulatory program certified pursuant to Public Resources Code Section 21080.5, which will be prepared by:

   (a) The State Energy Resources Conservation and Development Commission,

   (b) The Public Utilities Commission, or

   (c) The city or county in which the power plant and related facility would be located.

2. Cancellation of Williamson Act Contract No. 367 is required for development of the proposed thermal power plant and is therefore, determined to an early activity required for the project.

3. The cancellation of Williamson Act Contract No. 367 as an early activity will be further analyzed as part of an EIR, Negative Declaration, or other

document prepared for the proposed thermal power plant site or facility, as required under Section 15271.

4. The division of land is proposed in accordance with the County's General Plan and Zoning Ordinance. The project will not result in any adverse impacts to the environment.

The proposed project meets the criteria for Section 15271 and is exempt from the provisions of CEQA.

If you have any questions, please call me at 262-4454.

C:\Documents and Settings\tacosta-mena\Local Settings\Temporary Internet Files\OLKDF\ER 5785 (2).doc

DEPARTMENT OF CONSERVATION

DIVISION OF LAND RESOURCE PROTECTION
801 K STREET • MS 18-01 • SACRAMENTO, CALIFORNIA 95814
PHONE 916/324-0850 • FAX 916/327-3430 • TDD 916/324-2555 • WEBSITE conservation.ca.gov

RECEIVED
JAN 25 2007
FRESNO COUNTY
DEPT. OF
PUBLIC WORKS & PLANNING

January 19, 2007

Mr. Jared Nimer, Planner II
Fresno County Department of Public Works and Planning
Development Services Division
2220 Tulare Street, Sixth Floor
Fresno, CA 93721

Subject: Partial Cancellation of Land Conservation (Williamson Act) Contract ALCC No. 367 (RLCC 838); APN 027-060-78s portion - PAO Investments

Dear Mr. Nimer:

Thank you for submitting notice to the Department of Conservation (Department) as required by Government Code section 51284.1 for the above referenced matter.

The petition proposes to cancel a 12.82-acre portion of the parcel's 128.49 prime agricultural acres subject to Contract No. 367 for development of a 200-megawatt thermal power plant. The parcel's remaining 115 acres are currently undergoing the nonrenewal process for contract termination.

The site is located south and adjacent to West Panoche Road, approximately ¾ of a mile west of the intersection of Fairfax Avenue and West Panoche Road in Fresno County.

Cancellation Findings

Government Code Section 51282 states that tentative approval for cancellation may be granted only if the local government makes one of the following findings: 1) cancellation is **consistent** with purposes of the Williamson Act or 2) cancellation is in the **public interest**. The Department has reviewed the petition and information provided and offers the following comments.

Cancellation is consistent with the purposes of the Williamson Act

For the cancellation to be consistent with purposes of the Williamson Act, the Fresno County Board of Supervisors must make all of the following five findings: 1) a notice of nonrenewal has been served, 2) removal of adjacent land from agricultural use is unlikely, 3) the alternative use is consistent with the County's General Plan, 4) discontiguous patterns of urban development will not result, and 5) that there is no proximate noncontracted land which is available and suitable for the use proposed on the contracted land or that development of the contracted land would provide more contiguous patterns of urban development than development of proximate noncontracted land.

Provided the information received is accurate and correct, the Department concurs the Board has a basis to find cancellation of the 12.82-acre portion of the contract consistent with the purposes of the Williamson Act.

The landowner served a notice of nonrenewal. The 128.49-acre portion of Contract No. 367 (APN 027-060-78s) is scheduled to expire on December 31, 2016. Development of the proposed power generation facility will not negatively affect adjacent agricultural lands or cause their removal from agricultural use.

The proposed alternative use appears consistent with the agricultural land use policies contained in the Fresno County General Plan. The proposed alternative use will not produce discontiguous patterns of urban development and due to the location of the existing PG&E substation, the Department would concur that there is not proximate noncontracted land that is suitable or available for the alternative use proposed.

Cancellation is in the Public Interest

For the cancellation to be in the public interest, the Council must make findings with respect to all of the following: (1) other public concerns substantially outweigh the objectives of the Williamson Act and (2) that there is no proximate noncontracted land which is available and suitable for the use proposed on the contracted land or that development of the contracted land would provide more contiguous patterns of urban development than development of proximate noncontracted land. Our comments have already addressed the second finding required under public interest finding above.

In order to find that "other public concerns substantially outweigh the objectives of the Williamson Act," the Supreme Court has directed that the Board must consider the interest of the public as a whole in the value of the land for open space and agricultural use. Though the interests of the local and regional communities involved are also important, no decision regarding the public interest can be based exclusively on their parochialism. Moreover, the paramount 'interest' involved is the preservation of land in agricultural production. In providing for cancellation, the Legislature has recognized the relevance of other interests, such as housing, needed services, environmental protection through developed uses, economic growth and employment. However, it must be shown that open space objectives, explicitly and unequivocally protected by the act, are substantially outweighed by other public concerns before the cancellation can be deemed "in the public interest" (Sierra Club v City of Hayward (1981), 28 Cal. 3d. 840, 857).

As a general rule, land can be withdrawn from Williamson Act contract through the nine-year nonrenewal process. The Supreme Court has opined that cancellation is reserved for extraordinary situations (Sierra Club v. City of Hayward (1981), 28 Cal.3d 840).

Lastly, legislation effective January 1, 2005, requires the county assessor to send notice to the Department and landowner of the current fair market value of the land and of the opportunity to request a formal review from the assessor prior to any action giving tentative approval to the cancellation of any contract. (SB 1820, Machado, Chapter 794, Statutes of 2004 (Section 51283(a)). To date, the Department has not received the required notice of the parcel's cancellation valuation.

Thank you for the opportunity to provide comments on the proposed cancellation. Please provide our office with a copy of the Notice of the Public Hearing on this matter ten (10) working days before the hearing and a copy of the published notice of the Board's decision within 30 days of the tentative cancellation pursuant to section 51284. If you have any questions concerning our comments, please contact Adele Lagomarsino, Program Analyst at (916) 445-9411.

Sincerely,

Dennis J. O'Bryant

Dennis J. O'Bryant
Program Manager

9

SLIP SHEET - EXHIBIT #9

PANOCHE ENERGY CENTER, LLC'S COMMENTS TO STAFF'S PSA JULY 26, 2007 (1 BINDER)

10

County of Fresno

DEPARTMENT OF PUBLIC WORKS AND PLANNING
ALAN WEAVER, DIRECTOR

August 8, 2007

PAO Investments, LLC
45499 W. Panoche Rd.
Firebaugh, CA 93622

Dear Sir or Madam:

SUBJECT: General Plan Conformity Application – Panoche Energy Center LLC

Determine General Plan Conformity of Panoche Energy Center LLC's proposal to develop an electrical power generating facility on a 12.8-acre site in the AE-20 (Exclusive Agriculture, 20-acre minimum parcel size) District.

LOCATION: The proposed power generating facility is located on the south side of Panoche Road between Interstate 5 and Fairfax Avenue approximately 12.6 miles southwest of the City of Mendota (SUP. DIST.: 1) (APN: 027-060-78s).

APPLICANT: PAO Investments

EXHIBITS:

1. Location Map
2. Existing Zoning Map
3. Existing Land Use Map
4. Fresno County Adopted General Plan
5. Aerial Photograph of Proposed Power Generating Facility and Surrounding Area
6. Site Plan of Proposed Power Generating Facility

PROJECT DESCRIPTION:

On July 18, 2007, PAO Investments LLC submitted an application for determination of General Plan Conformity on a 12.8-acre parcel for the purposes of establishing a power generating facility. The proposed power generating facility is located on the south side of Panoche Road between Interstate 5 and Fairfax Avenue approximately 12.6 miles southwest of the City of Mendota. The proposed facility would consist of four General Electric LMS100 natural gas-fired Combustion Turbine Generators, with a total net generating capacity of approximately 400 MW.

Other site characteristics include the gas pipeline, 230kV transmission line, expansion area for the PG&E electrical substation, and a basin for storm water retention (Exhibit 6).

BACKGROUND:

On April 24, 2007, the Fresno County Board of Supervisors approved a request for partial cancellation of the Williamson Act Contract, to remove the subject 12.8-acre area from Agricultural Land Conservation Contract No. 367 restrictions. Approval of the partial cancellation request required the Board to make five specified findings. One of the required findings was a determination that the proposed alternate use is consistent with the General Plan. The Board determined that the five findings could be made and, therefore, approved the partial cancellation.

EXISTING LAND USE:

The existing parcel is zoned AE-20 (Exclusive Agriculture, 20-acre minimum parcel size). The site is designated Agriculture in the Fresno County General Plan and is subject to Agricultural Land Conservation Contract No. 367.

The subject site is currently in agricultural use planted in pomegranates. A PG&E electrical substation exists adjacent to the northeast of the project area. Other adjacent land consists of pomegranate orchards.

PROCEDURAL CONSIDERATIONS / PURPOSE OF REPORT:

The California Energy Commission's (CEC) Preliminary Staff Assessment (PSA) regarding the proposed power generating facility indicated that the CEC was unable to determine if the proposed project is consistent with the Fresno County General Plan.

GENERAL PLAN POLICY CONSIDERATIONS

The proposed project and surrounding land is designated for Agriculture in the Fresno County General Plan. As previously-mentioned, the subject site is zoned for agricultural land uses (AE-20). The existing AE-20 zoning (Exhibit 2) is reflective of the County General Plan land use designation for this area.

The Fresno County General Plan contains specific policies related to agricultural land and the protection of those lands as the County's most valuable natural resource and its historical basis of its economy. General Plan Policy LU-A.1 directs urban growth away from valuable agricultural lands to cities and unincorporated communities.

Policy LU-A.3 states that the County shall allow special agricultural uses, agriculturally-related activities and certain non-agricultural uses in areas designated Agriculture. Table LU-3 lists typical uses allowed in areas designated Agriculture. Approval of those and similar uses is subject to a determination that certain criteria can be met. This list is not intended to be inclusive of all uses that can be considered for development. The proposed power generating facility is similar to other allowed uses which provide a needed service to the surrounding community or the larger area. Table LU-3 includes uses which provide a public benefit to the surrounding community or larger area, such as sewage treatment plants, solid waste disposal, wireless communication facilities and electrical substations. For proposed power generating facilities with a net generating capacity of less than 50 MW, the proposed project requires approval from Fresno County. In those instances, an Unclassified Conditional Use Permit is required to be submitted for review and for a determination before the Fresno County Planning Commission and/or Board of Supervisors. In this case, because the proposed project would have a net generating capacity of 400 MW, an Unclassified Conditional Use Permit was determined to not be required. However, the Fresno County Board of Supervisors has, in the past, approved Unclassified Conditional Use Permits for proposed power generating facilities on land designated for Agriculture and zoned AE-20.

Regarding the criteria to be considered in approval of such uses, as specified in Policy LU-A.3, staff believes the criteria are met sufficiently to determine that the proposed project is consistent with the Fresno County General Plan.

Criterion "a" is met in that the facility is proposed at this non-urban location because of the existing infrastructure installed at the adjacent Pacific Gas and Electric substation and the existing high-volume natural gas lines and 230 kilovolt transmission lines located on the subject parcel. The existing infrastructure allows for efficient interconnection, which reduces impacts on adjacent land. Criterion "b" can be met because a site selection investigation was performed by the applicant, looking for land that was in sufficient proximity to the infrastructure listed above. No less productive agricultural lands were identified within sufficient proximity to serve as a reasonable alternative. The proposed power generating facility is estimated to have a maximum annual groundwater demand of 1,154 acre-feet. Based on the environmental documentation submitted to the California Energy Commission, the proposed facility will not have a significant effect on groundwater resources, and would meet Criterion "c". The proposed facility is located approximately 12.6 miles from the city of Mendota and approximately 13.7 miles from the city of Firebaugh. While a location closer to sources for employees would be preferable, other site requirements preclude such a location.

CONCLUSION:

Table LU-A.3 lists typical uses allowed on land designated for Agriculture in Fresno County. The identified uses are not intended to be an exhaustive listing of all allowed uses, but instead are typical uses allowed. Other similar uses can also be permitted on land designated for Agriculture. It has been determined that the proposed power generating facility is similar to other non-agricultural uses listed in Table LU-3 of the Fresno County General Plan. Further, the Panoche Energy Center facility meets the criteria for allowing such a use as described in Policy LU-A.3 of the General Plan. The development of the proposed use on the subject property is consistent with the Fresno County General Plan.

This determination was supported by the Board of Supervisors on April 24, 2007, when the request for partial cancellation of Agricultural Land Conservation Contract No. 367 was approved.

No additional land use entitlement review by Fresno County is required for the development of the proposed power generating facility.

If you have questions regarding this General Plan Conformity review, please call me at (559) 262-4022.

Sincerely,

Jared Nimer, Planner
Development Services

JN:hr
G:\4360Devs&Pln\PROJSEC\PROJDOCS\GPC\Panoche Energy Center\GPC letter.doc

Enclosures

c: Bernard Jimenez, Division Manager
Will Kettler, Principal Manager
Margie McHenry, Senior Planner
Zachary Redmond, Deputy County Counsel
Marcus Magness

EXHIBIT 1

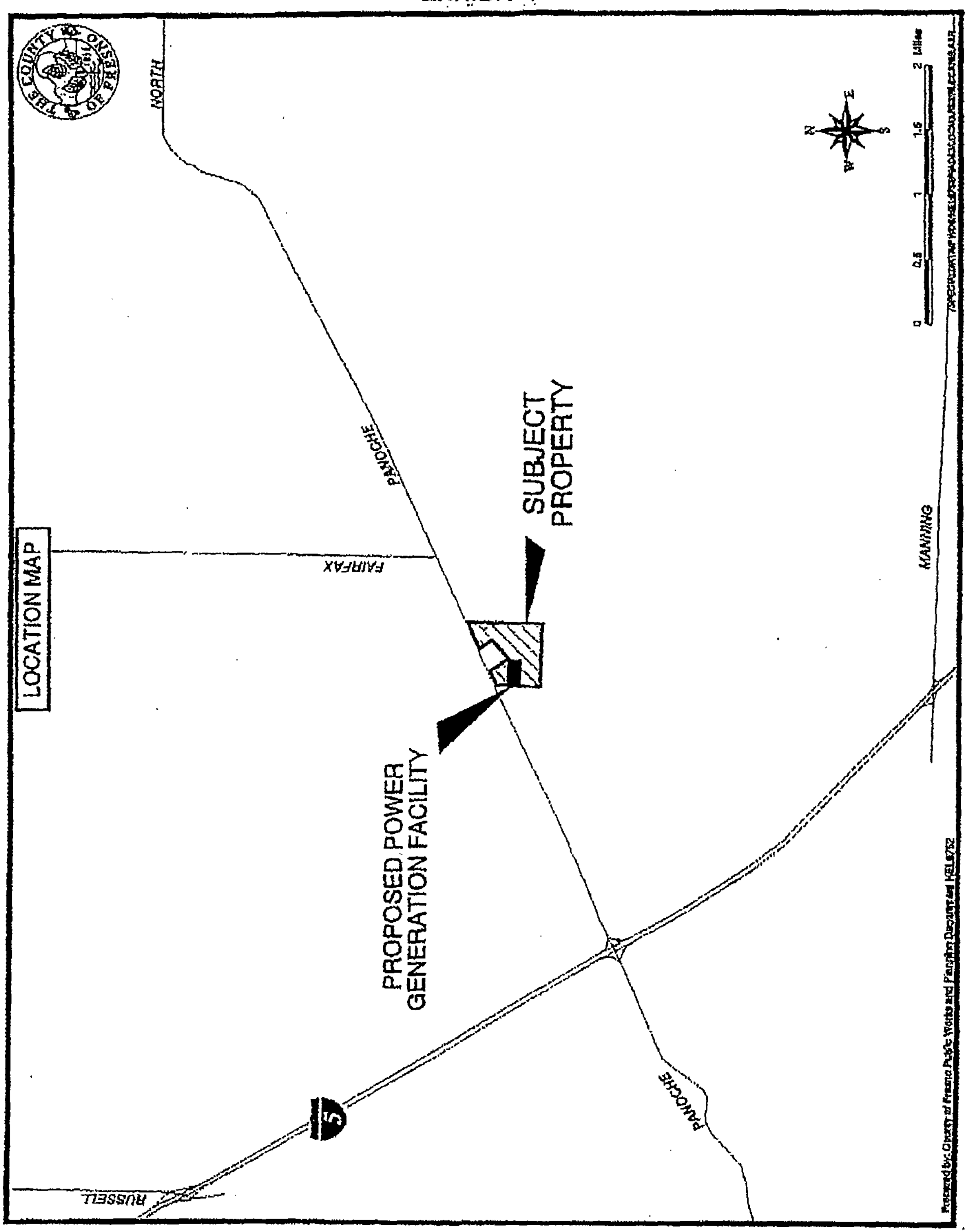

LOCATION MAP
NORTH
PANOCHE
FAIRFAX
SUBJECT PROPERTY
PROPOSED POWER GENERATION FACILITY
MANNING
PANOCHE
RUSSELL
5
0
0.5
1
1.5
2 Miles
N
E
S
W

EXHIBIT 2

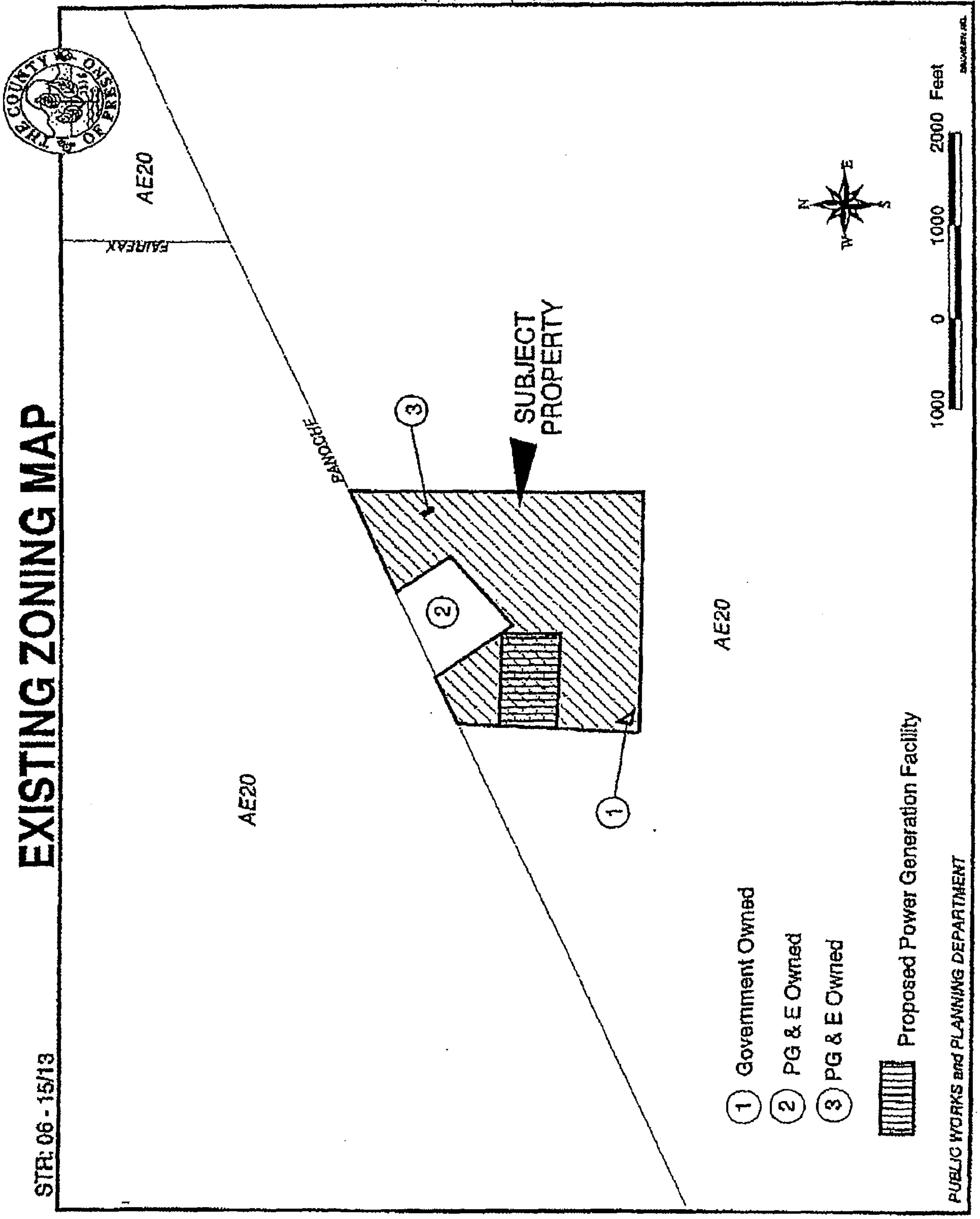

EXISTING ZONING MAP
STR: 06 - 15/13
THE COUNTY OF FRESNO
AE20
AE20
AE20
FAIRFAX
PANOCHE
SUBJECT PROPERTY
1
2
3
N
E
S
W
1000
0
1000
2000 Feet
1 Government Owned
2 PG & E Owned
3 PG & E Owned
Proposed Power Generation Facility
PUBLIC WORKS and PLANNING DEPARTMENT

EXHIBIT 3

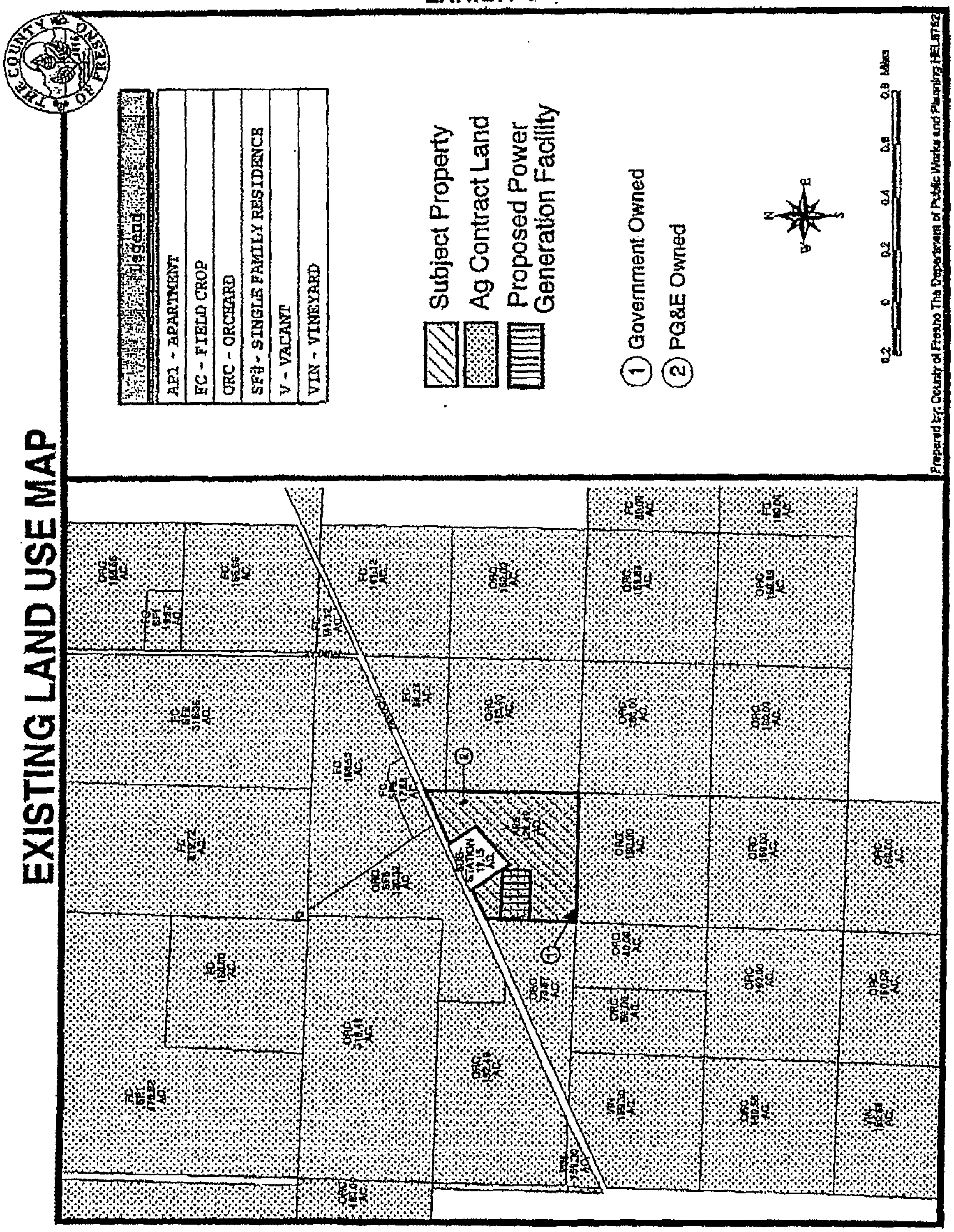

EXISTING LAND USE MAP
THE COUNTY OF FRESNO
Legend
AP1 - APARTMENT
FC - FIELD CROP
ORC - ORCHARD
SFR - SINGLE FAMILY RESIDENCE
V - VACANT
VIN - VINEYARD
Subject Property
Ag Contract Land
Proposed Power Generation Facility
1 Government Owned
2 PG&E Owned
SUB-STATION
Prepared by: County of Fresno The Department of Public Works and Planning

EXHIBIT 4

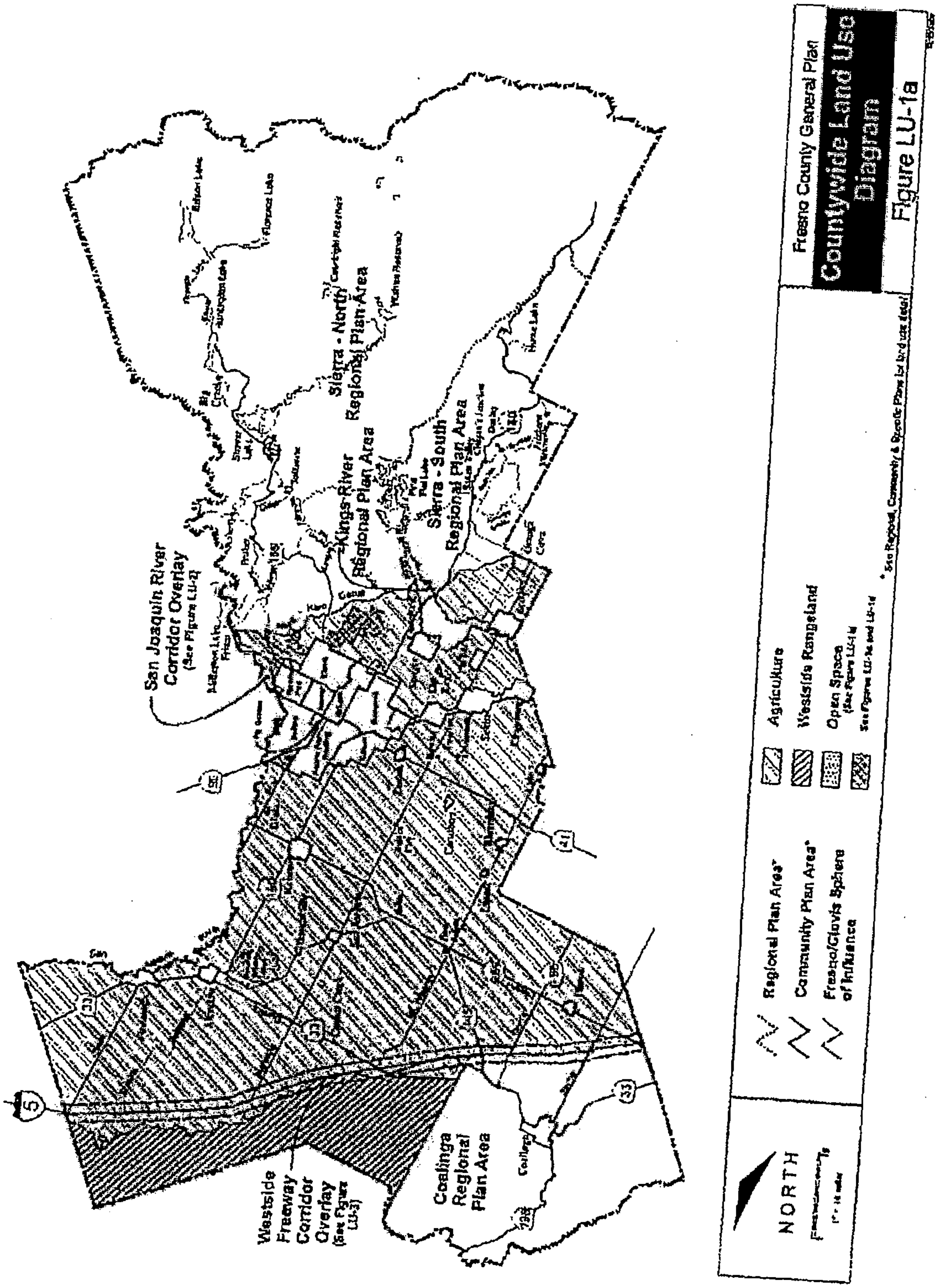

Fresno County General Plan
Countywide Land Use Diagram
Figure LU-1a
Sierra - North Regional Plan Area
Kings River Regional Plan Area
Sierra - South Regional Plan Area
San Joaquin River Corridor Overlay (See Figure LU-2)
Westside Freeway Corridor Overlay (See Figure LU-3)
Coalinga Regional Plan Area
Regional Plan Area*
Community Plan Area*
Fresno/Clovis Sphere of Influence
Agriculture
Westside Rangeland
Open Space
NORTH

EXHIBIT 5

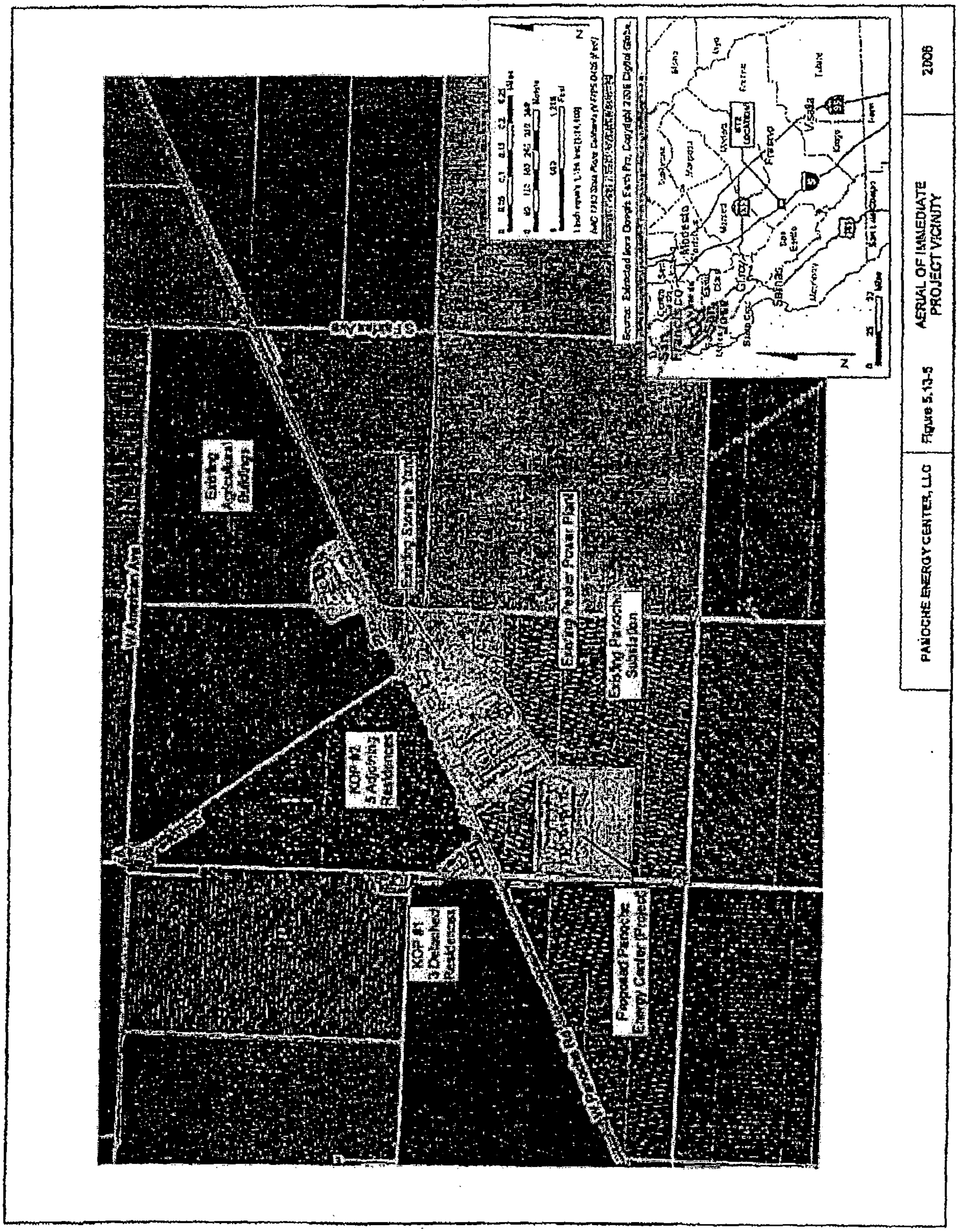
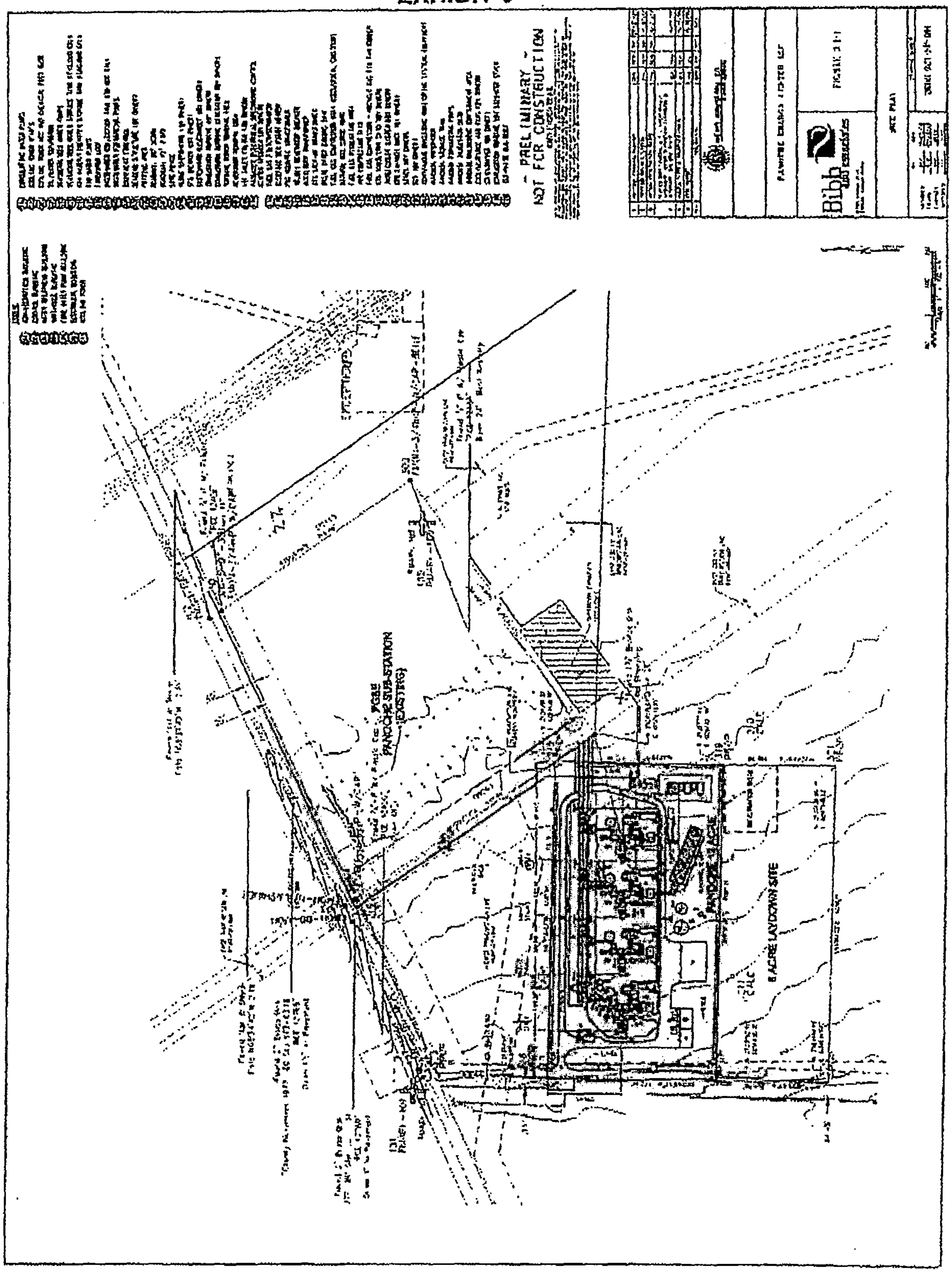

Existing Agricultural Buildings
Existing Switching Station
Existing Peaker Power Plant
Existing Panoche Substation
KOP #2 5 Adjoining Residences
KOP #1 3 Detached Residences
Proposed Panoche Energy Center Project
SITE LOCATION
Fresno
Visalia
Modesto
PANOCHE ENERGY CENTER, LLC
Figure 5.13-5
AERIAL OF IMMEDIATE PROJECT VICINITY
2006

EXHIBIT 6


PRELIMINARY - NOT FOR CONSTRUCTION
PG&E PANOCHE SUB-STATION (EXISTING)
8 ACRE LAYDOWN SITE
Bibb

County of Fresno

DEPARTMENT OF PUBLIC WORKS AND PLANNING
ALAN WEAVER, DIRECTOR

August 8, 2007

PAO Investments, LLC
45499 W. Panoche Rd.
Firebaugh, CA 93622

Dear Sir or Madam:

SUBJECT: General Plan Conformity Application – Starwood Power-Midway, LLC

Determine General Plan Conformity of Starwood Power-Midway, LLC's proposal to develop an electrical power generating facility on a 5.6-acre site in the AE-20 (Exclusive Agriculture, 20-acre minimum parcel size) District.

LOCATION: The proposed power generating facility is located on the south side of Panoche Road between Interstate 5 and Fairfax Avenue approximately 12.6 miles southwest of the City of Mendota (SUP. DIST.: 1) (APN: 027-060-78s).

APPLICANT: PAO Investments

EXHIBITS:

1. Location Map
2. Existing Zoning Map
3. Existing Land Use Map
4. Fresno County Adopted General Plan
5. Aerial Photograph of Proposed Power Generating Facility and Surrounding Area
6. Site Plan of Proposed Power Generating Facility

PROJECT DESCRIPTION:

On July 18, 2007, PAO Investments LLC submitted an application for determination of General Plan Conformity on a 5.6-acre parcel for the purposes of establishing a power generating facility. The proposed power generating facility is located on the south side of Panoche Road between Interstate 5 and Fairfax Avenue approximately 12.6 miles southwest of the City of Mendota. The proposed facility would consist of two FT8-3 SwiftPac Combustion Turbine Generator units installed in a simple-cycle power plant arrangement, with a total net generating

DEVELOPMENT SERVICES DIVISION
2220 Tulare Street, Sixth Floor / Fresno, California 93721 / Phone (559) 262-4055 / 262-4079 / 262-4302 / 262-4022 / FAX 262-4893
Equal Employment Opportunity • Affirmative Action • Disabled Employer

capacity of approximately 120 MW. Off-site improvements associated with the project include an approximate 300-foot electric transmission line to tie into the PG&E Substation, a 1,200-foot underground water pipeline connecting the project to the existing CalPeak Panoche plant well adjacent to the project site, 50 feet of new gas transmission line and a gas metering set which will tap into the existing PG&E gas trunkline.

BACKGROUND:

On April 24, 2007, the Fresno County Board of Supervisors approved a request for partial cancellation of the Williamson Act Contract, to remove the subject 5.6-acre area from Agricultural Land Conservation Contract No. 367 restrictions. Approval of the partial cancellation request required the Board to make five specified findings. One of the required findings was a determination that the proposed alternate use is consistent with the General Plan. The Board determined that the five findings could be made and, therefore, approved the partial cancellation.

EXISTING LAND USE:

The existing parcel is zoned AE-20 (Exclusive Agriculture, 20-acre minimum parcel size). The site is designated Agriculture in the Fresno County General Plan and is subject to Agricultural Land Conservation Contract No. 367.

The subject site is currently used as a storage-yard by CalPeak Power. A PG&E electrical substation exists adjacent to the southwest of the project area. Other adjacent land consists of pomegranate orchards.

PROCEDURAL CONSIDERATIONS / PURPOSE OF REPORT:

The California Energy Commission's (CEC) Preliminary Staff Assessment (PSA) regarding the proposed power generating facility indicated that the CEC was unable to determine that the proposed project is consistent with the Fresno County General Plan.

GENERAL PLAN POLICY CONSIDERATIONS

The proposed project and surrounding land is designated for Agriculture in the Fresno County General Plan. As previously-mentioned, the subject site is zoned for agricultural land uses (AE-20). The existing AE-20 zoning (Exhibit 2) is reflective of the County General Plan land use designation for this area.

The Fresno County General Plan contains specific policies related to agricultural land and the protection of those lands as the County's most valuable natural resource and its historical basis of its economy. General Plan Policy LU-A.1 directs urban growth away from valuable agricultural lands to cities and unincorporated communities.

Policy LU-A.3 states that the County shall allow special agricultural uses, agriculturally-related activities and certain non-agricultural uses in areas designated Agriculture. Table LU-3 lists typical uses allowed in areas designated Agriculture. Approval of those and similar uses is subject to a determination that certain criteria can be met. This list is not intended to be inclusive of all uses that can be considered for development. The proposed power generating facility is similar to other allowed uses which provide a needed service to the surrounding community or the larger area. Table LU-3 includes uses which provide a public benefit to the surrounding community or larger area, such as sewage treatment plants, solid waste disposal, wireless communication facilities and electrical substations. For proposed power generating facilities with a net generating capacity of less than 50 MW, the proposed project requires approval from Fresno County. In those instances, an Unclassified Conditional Use Permit is required to be submitted for review and for a determination before the Fresno County Planning Commission and/or Board of Supervisors. In this case, because the proposed project would have a net generating capacity of 120 MW, an Unclassified Conditional Use Permit was determined to not be required. However, the Fresno County Board of Supervisors has, in the past, approved Unclassified Conditional Use Permits for proposed power generating facilities on land designated for Agriculture and zoned AE-20.

Regarding the criteria to be considered in approval of such uses, as specified in Policy LU-A.3, staff believes the criteria are met sufficiently to determine that the proposed project is consistent with the Fresno County General Plan.

Criterion "a" is met in that the facility is proposed at this non-urban location because of the existing infrastructure installed at the adjacent Pacific Gas and Electric substation and the existing high-volume natural gas lines and 115 kilovolt transmission lines located on the subject parcel. The existing infrastructure allows for efficient interconnection, which reduces impacts on adjacent land. Criterion "b" can be met because a site selection investigation was performed by the applicant, looking for land that was in sufficient proximity to the infrastructure listed above. No less productive agricultural lands were identified within sufficient proximity to serve as a reasonable alternative. The proposed power generating facility is estimated to have a maximum annual groundwater demand of 135.6 acre-feet. Based on the environmental documentation submitted to the California Energy Commission, the proposed facility will not have a significant effect on groundwater resources, and would meet Criterion "c". The proposed facility is located approximately 12.6 miles from the city of Mendota and approximately 13.7 miles from the city of Firebaugh. While a location closer to sources for the two required employees would be preferable, other site requirements preclude such a location.

CONCLUSION:

Table LU-A.3 lists typical uses allowed on land designated for Agriculture in Fresno County. The identified uses are not intended to be an exhaustive listing of all allowed uses, but instead are typical uses allowed. Other similar uses can also be permitted on land designated for Agriculture. It has been determined that the proposed power generating facility is similar to other non-agricultural uses listed in Table LU-3 of the Fresno County General Plan. Further, the Starwood Power-Midway facility meets the criteria for allowing such a use as described in Policy LU-A.3 of the General Plan. The development of the proposed use on the subject property is consistent with the Fresno County General Plan.

This determination was supported by the Board of Supervisors on April 24, 2007, when the request for partial cancellation of Agricultural Land Conservation Contract No. 367 was approved.

No additional land use entitlement review by Fresno County is required for the development of the proposed power generating facility.

If you have questions regarding this General Plan Conformity review, please call me at (559) 262-4022.

Sincerely,

Jared Nimer, Planner
Development Services

JN:hr
G:\4360Devs&Pln\PROJSEC\PROJDOCS\GPC\Starwood Power - Midway\GPC letter.doc

Enclosures

c: Bernard Jimenez, Division Manager
Will Kettler, Principal Planner
Margie McHenry, Senior Planner
Zachary Redmond, Deputy County Counsel
Marcus Magness

EXHIBIT 1

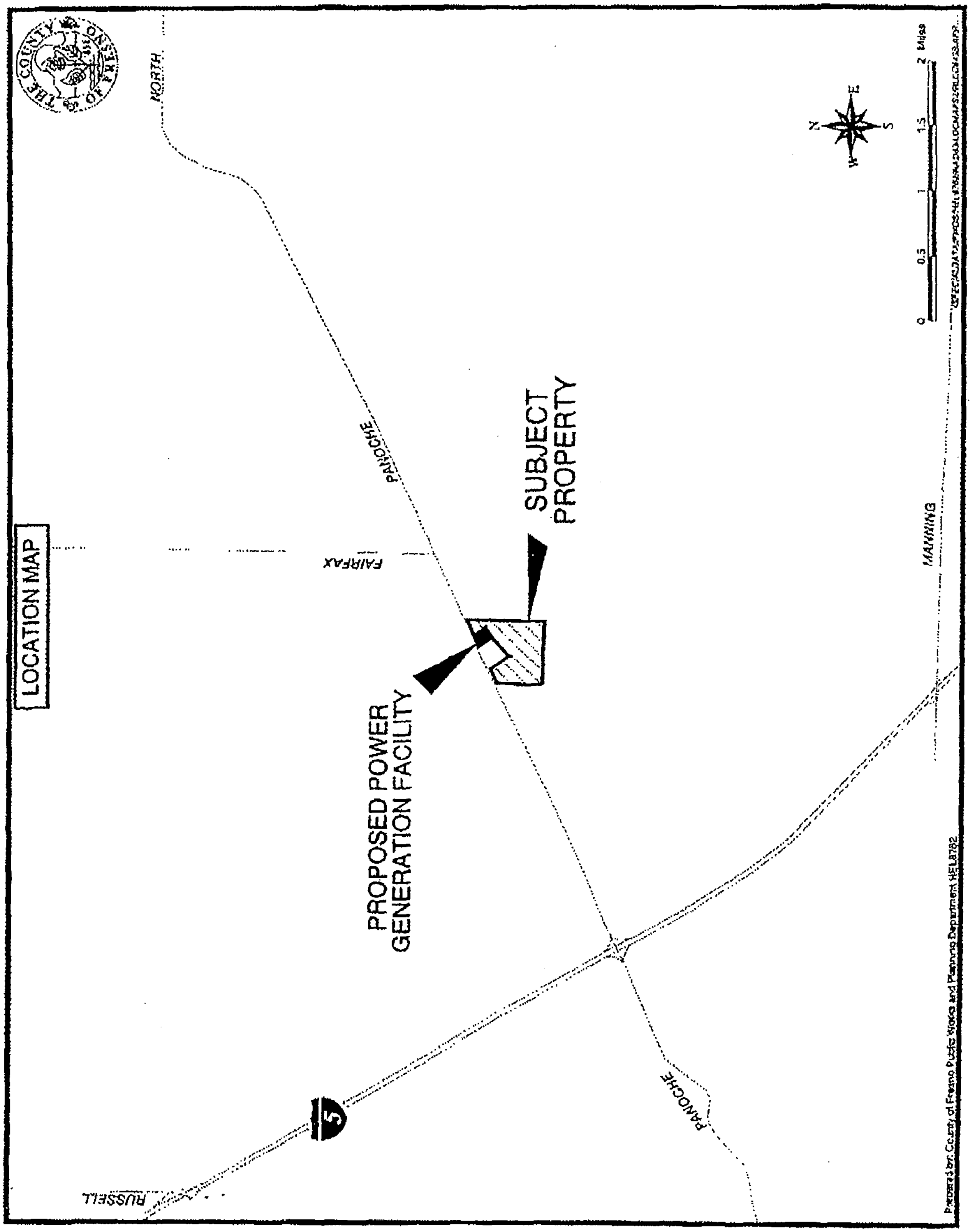

LOCATION MAP
NORTH
PANOCHE
FAIRFAX
SUBJECT PROPERTY
PROPOSED POWER GENERATION FACILITY
MANNING
RUSSELL
5
PANOCHE
0
0.5
1
1.5
2 Miles
N
E
S
W

EXHIBIT 2

STR: 06 - 15/13

EXISTING ZONING MAP

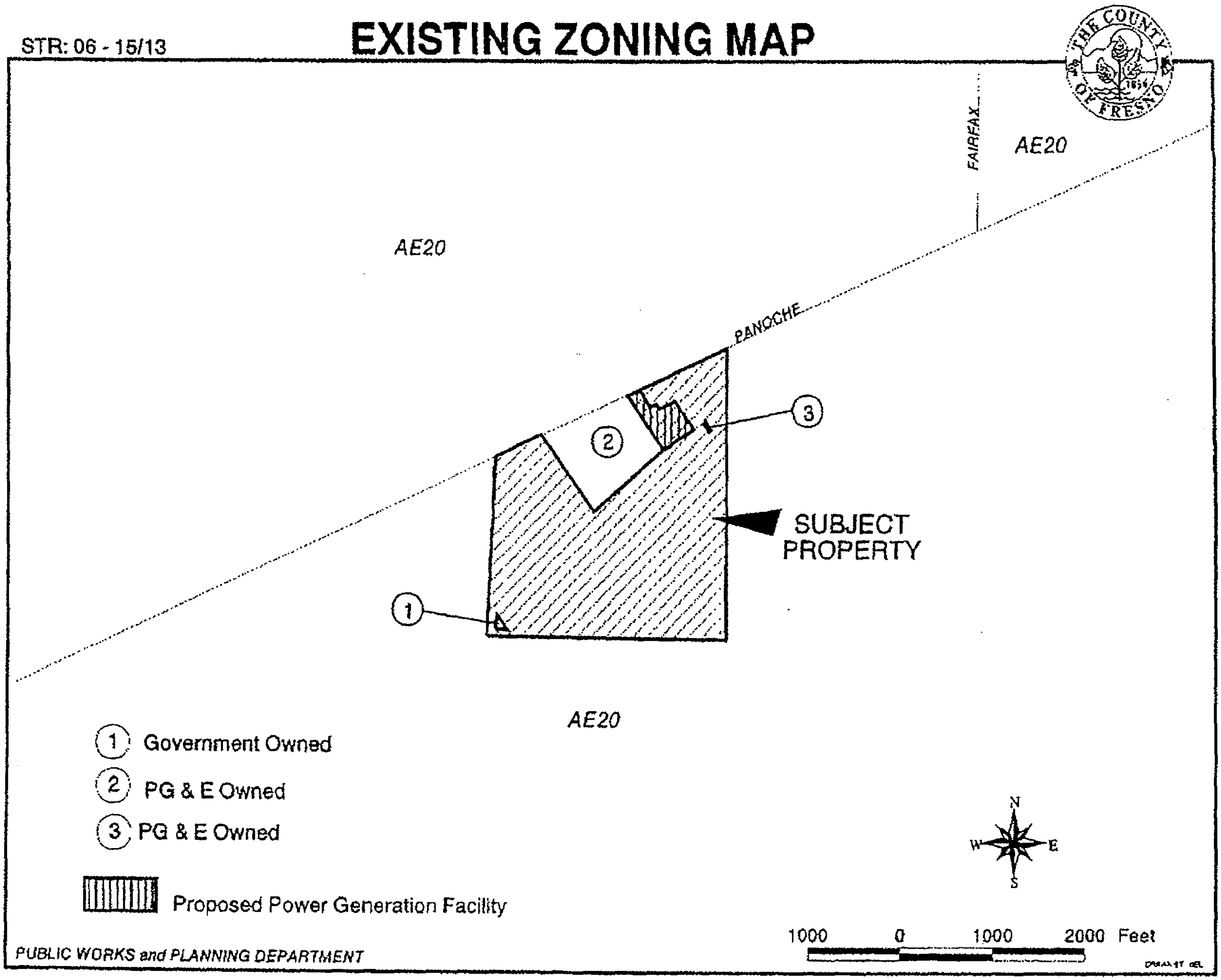


EXHIBIT 3

EXISTING LAND USE MAP

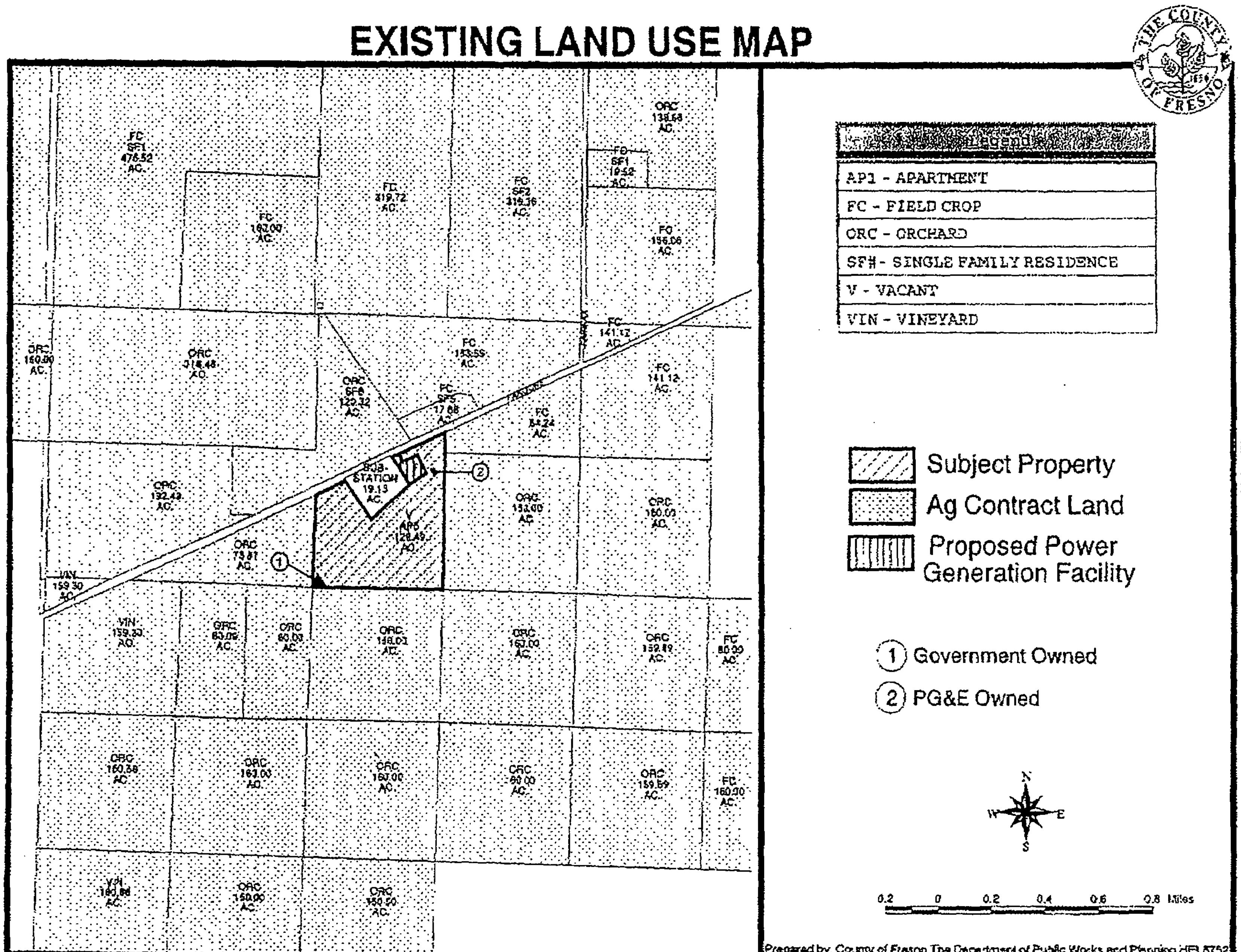


EXHIBIT 4

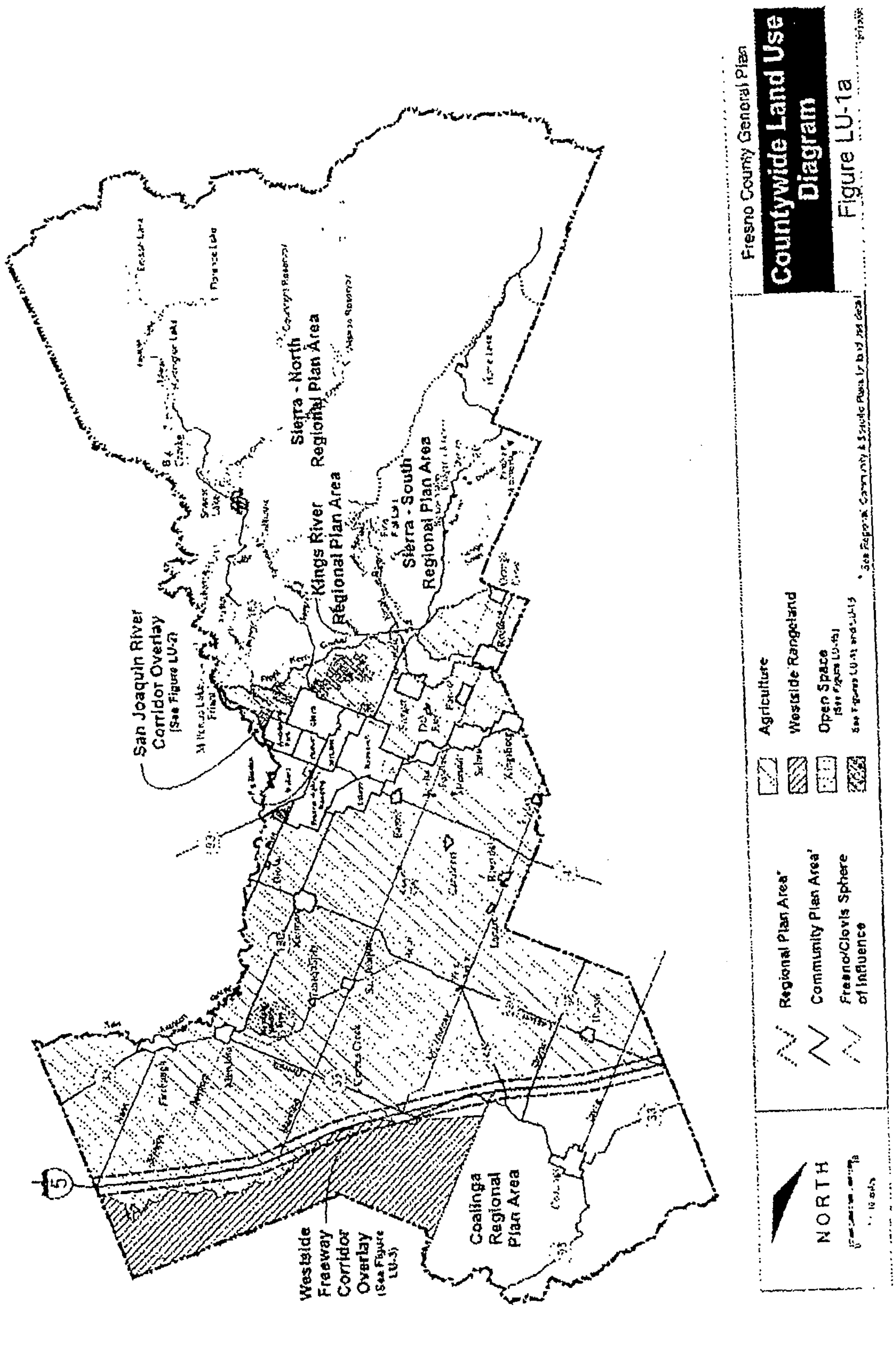

Fresno County General Plan
Countywide Land Use Diagram
Figure LU-1a
Sierra - North Regional Plan Area
Sierra - South Regional Plan Area
Kings River Regional Plan Area
San Joaquin River Corridor Overlay (See Figure LU-2)
Westside Freeway Corridor Overlay (See Figure LU-3)
Coalinga Regional Plan Area
Regional Plan Area*
Community Plan Area*
Fresno/Clovis Sphere of Influence
Agriculture
Westside Rangeland
Open Space
NORTH

EXHIBIT 5

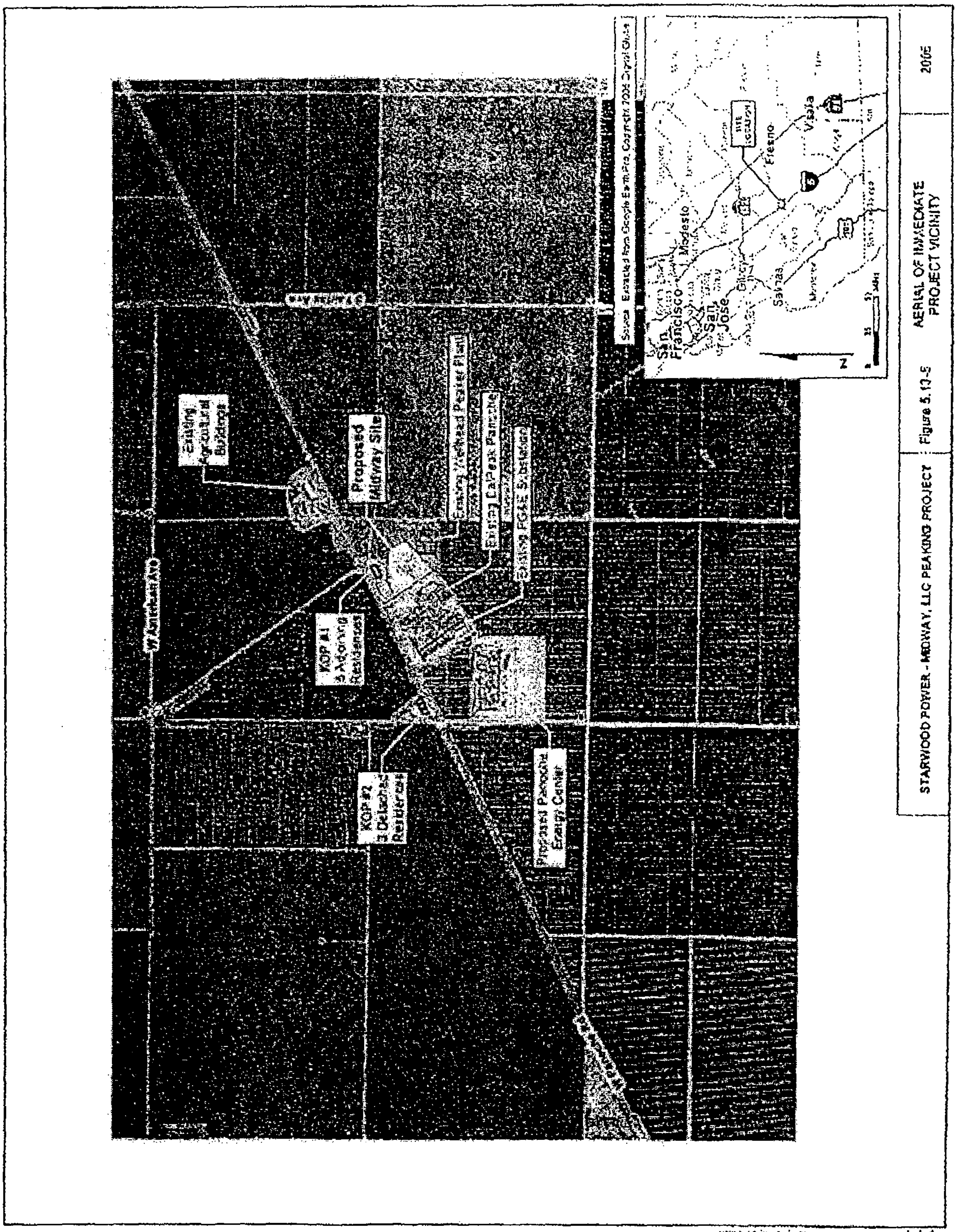
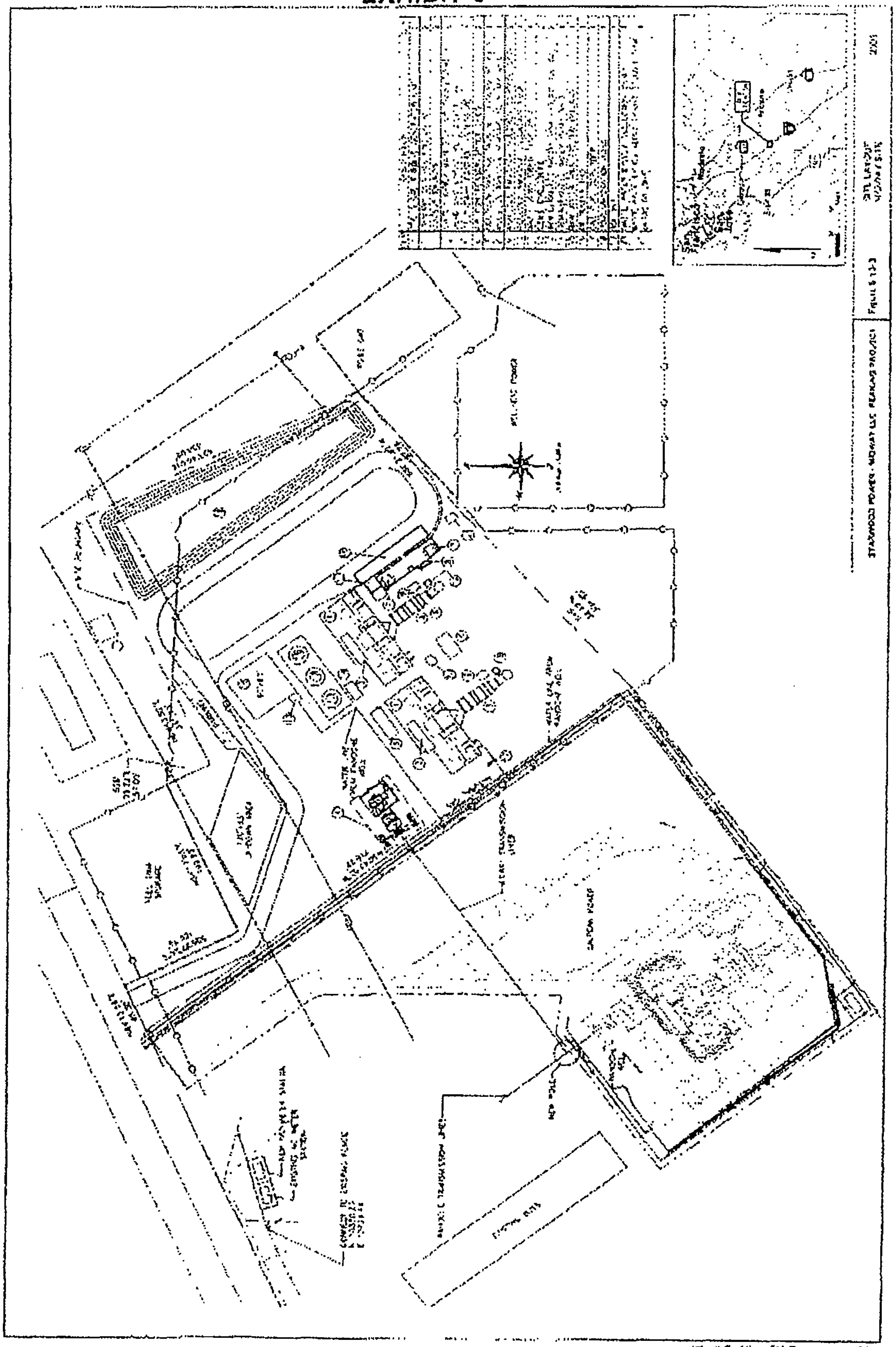

Proposed Midway Site
Existing Agricultural Buildings
Proposed Panoche Energy Center
Existing PG&E Substation
San Francisco
San Jose
Modesto
Fresno
Visalia
Salinas
STARWOOD POWER - MIDWAY, LLC PEAKING PROJECT
Figure 5.13-5
AERIAL OF IMMEDIATE PROJECT VICINITY
2005

EXHIBIT 6



11

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Sacramento Fish and Wildlife Office
2800 Cottage Way, Room W-2605
Sacramento, California 95825-1846

In reply refer to:
1-1-07-F-0255

AUG 21 2007

Memorandum

To: Field Supervisor, Sacramento Fish and Wildlife Office, Sacramento, California

From: Assistant Field Supervisor, Endangered Species Program, Sacramento, California

Kenneth Sanchez

Subject: Formal Consultation Regarding the Panoche Energy Center, Fresno County, California

This letter is in response to a request from the applicant Panoche Energy Center (PEC), for the U.S. Fish and Wildlife Service's (Service) assistance with the Panoche Energy Center Project (proposed project). The PEC signed a Memorandum of Understanding (MOU) on August 7, 2007, with the Service. The MOU outlines the specific conservation measures the PEC will implement to conserve the endangered San Joaquin kit fox (*Vulpes macrotis mutica*) (kit fox) and to avoid jeopardy to this species consistent with the Endangered Species Act of 1973, as amended (Act) (16 U.S.C. 1531). The MOU also formalizes the Service's agreement to facilitate a Federal nexus for the purposes of conducting consultation pursuant to section 7 of the ESA, as described in its implementing regulations (50 CFR 402).

The Service has determined that the proposed project is likely to adversely affect the kit fox; therefore, this document represents the Service's biological opinion on the effects of the proposed project on the kit fox, in accordance the Act. No critical habitat is present for any federally-listed species, therefore none will be adversely modified or destroyed.

The findings and recommendations in this consultation are based on: (1) a May 18, 2007, *Panoche Energy Center Project Biological Assessment* prepared by URS Corporation, (2) electronic mail messages between PEC, URS Corporation and Susan Jones of the Service dated between January 2007, through July 2007, (3) and other information available to the Service.

Consultation History

February - May, 2007: The applicant convened and facilitated telephone conferences with the Service and other resource agency staff to gather biological data relating to federally-protected species.

March 16, 2007: Conference call with Susan Jones of the Service, applicant and the California Energy Commission (CEC) representative. The call discussed the need for a biological assessment and conservation measures for the San Joaquin kit fox.

April 2007: The Service was contacted to assist the PEC in determining the potential effects of the proposed project to threatened, endangered, and candidate species that occur or could potentially occur in the project study area.

April 13, 2007: A CEC biology workshop was held with representatives from the Service, California Department of Fish and Game (CDFG), CEC, and PEC staff. These agency representatives reviewed the project, draft project documents, and ancillary project features to help identify significant environmental issues, species of concern, and the potential scope and intensity of direct, indirect, and cumulative impacts to Federal and State protected species.

BIOLOGICAL OPINION

Description of the Proposed Action

Construction Sequence, Schedule & Equipment

Construction of the generating facility, from site preparation and grading to commercial operation, is expected to take place from February 2008 to August 2009.

Project Schedule and Workforce

The major construction schedule milestones are to begin construction in February 2008, Startup and test should begin in May 2009, and commercial operation is estimated to begin in August 2009.

Execution Plans – Engineering and Construction Phases

This is an engineering, procurement, and construction (EPC) type project. As such, a single General Contractor will be selected by the PEC for the design, procurement, and construction of the facility. Subcontractors will be selected by the General Contractor for specialty work portions as needed.

Engineering and Pre-Construction Mobilization

Engineering activities will begin following final approval of the proposed project by the CEC and completion of obligatory discretionary permitting processes; which are anticipated by late 2007. Staff from the engineering and construction groups will work together in the same office to prepare a safe, qualitative, cost effective, and sequentially effective plan for the proposed project. The initial focus will include the purchase and delivery of engineered equipment and specialty, long-lead material. Facility design will include early milestones to complete the civil, structural, and mechanical equipment aspects of the project. As the ground-breaking occurs and site grading commences, the design and procurement continues to support the overall schedule and reliability of the final project. The General Contractor is anticipated to mobilize within four months after notice to proceed.

Construction Facilities

Mobile trailers or similar suitable facilities (e.g., modular offices) will be used as construction offices for the owner, contractor, and subcontractor personnel.

Construction Parking

Construction parking areas will be within existing site boundaries of the designated laydown area, south of the plant site. Construction access will be from West Panoche Road, via a new access road. These areas will provide adequate parking space for construction personnel and visitors during construction and will be maintained for stability and safety.

Laydown and Storage

Areas within the energy center boundary and the 8-acre laydown area immediately to the south of the proposed energy center locale will be used as off-load and staging areas. These areas will be restored to agricultural use once construction is complete.

Emergency Facilities

The General Contractor will have a Safety Coordinator who will prepare a site-specific safety plan. Emergency services will be coordinated with the County of Fresno Fire Department and local hospital in the City of Mendota. An urgent care facility will be contacted to set up non-emergency physician referrals. First aid kits will be provided in the construction offices and regularly maintained. At least one person trained in first aid will be part of the construction crew. In addition, all foremen and supervisors will be given first aid training.

Construction Utilities

During construction, temporary utilities will be provided for the construction offices, laydown area, and the project site. Temporary construction power will initially be provided by using diesel- and gas-powered generators. Eventually, temporary construction power will be supplied by a connection to the adjacent Pacific Gas and Electric (PG&E) electrical substation. Water trucks and potable water delivery will initially provide construction water. As the project matures and the build-out of water wells is completed, the onsite water wells will then be used as the source of construction water. Portable toilets will be provided throughout the site during construction.

Site Services

The General Contractor will provide the following site services:

- Environmental health and safety training
- Site security
- Site first aid
- Construction testing (e.g., nondestructive examination, soil compaction)
- Site fire protection and extinguisher maintenance
- Furnishing and servicing of sanitary facilities
- Trash collection and disposal
- Disposal of hazardous materials and waste in accordance with local, state, and federal regulations

Construction Equipment and Materials Delivery

Materials and supplies will be delivered to the site by truck. Truck deliveries of construction materials and equipment will generally occur on weekdays between 6:00 a.m. and 6:00 p.m.; however, some larger heavy load deliveries may be delivered outside those hours. Site access will be controlled for personnel and vehicles.

Project Features & Construction Activities

The following subsections describe the specific project features and construction-related activities.

Civil/Structural Features

The power block will consist of four separate simple-cycle combustion turbine power generation trains, each consisting of one General Electric LMS100 combustion turbine/generator unit (CTG), an air inlet system, an intercooler and variable bleed valve silencer, a NOx selective catalyst reduction (SCR) system, one stack, a power control module, an intercooler motor control center, a fuel gas filter/separator, and a step-up transformer. In addition to the four combustion turbine power generation trains, there will be a five-cell cooling tower, an ammonia storage tank, a natural gas compressor facility, a water treatment facility, and two auxiliary transformers. There will also be balance-of-plant (BOP) mechanical and electrical equipment.

The major equipment will be supported on reinforced concrete foundations at grade, with pile-supports as necessary. Individual reinforced pads at grade will be used to support the BOP mechanical and electrical equipment. The gas compressors will be in an enclosed acoustic building for noise attenuation. The water treatment equipment will also be in an enclosed building.

Stacks

The SCR system will include an integral stack/silencer system. The stack will be a self-supporting steel stack, 90 feet tall, and will include the associated appurtenances, such as sampling ports, exterior ladders, side step platforms, and electrical grounding grid.

Buildings

The plant buildings will include an administration and control building, a warehouse building, a water treatment building, a firewater pump building, switchgear modules, and a gas compressor building. The administration and control building will house the administrative areas and the control room for the new facility. All of the buildings will be supported on mat foundations or individual spread footings.

Transformer Foundations and Fire Walls

There will be four 13.8kV to 230kV step-up oil-filled transformers and two auxiliary oil-filled transformers. Each will be supported on reinforced concrete foundations at grade, with pile-supports as necessary. Construction of a concrete retention basin around each transformer will provide oil containment, in the event of a failure of a transformer. Concrete firewalls are planned for each step-up transformer and auxiliary transformer to limit a potential transformer fire to its concrete basin area.

Yard Tanks

The yard water storage tanks will include the demineralized water storage tank (240,000 gallons), the raw water/firewater storage tank (500,000 gallons), and the wastewater collection tank (20,000 gallons). The yard storage tanks will be vertical, cylindrical, field-erected, or shop-fabricated steel tanks. Each tank will be supported on a suitable foundation consisting of either a reinforced concrete ring wall with an interior bearing layer of compacted sand for the tank bottom, or a reinforced concrete mat.

Roads

The new site will be accessed from Panoche Road via a new asphalt paved entrance road. All new roads, miscellaneous access drives, and permanent parking areas within the site boundaries will be asphalt paved.

Site Security Fencing

A chain-link security fence surrounding the perimeter of the site will enclose the new facility. In addition, the switchyard will be enclosed within a chain-link fence for the safety of the workforce. A controlled-access gate will be located at the entrance off the new access road from Panoche Road. During construction, a temporary chain-link security fence will be erected around the outside perimeter of the laydown site. This fence will be removed at the conclusion of the construction phase.

Site Grading and Drainage

The plant site will consist of paved roads, paved parking areas, and graveled areas. Storm water will be conveyed by overland flow and swales to an infiltration basin located at the southeast corner of the project site. The infiltration basin will serve as a storm water treatment facility to manage the quantity of storm water runoff from the project site. The infiltration basin is sized to capture 85 percent of the annual storm water runoff from the site according to standards set in the "California Storm Water Best Management Practices (BMP) Handbook." The infiltration basin will also serve to manage peak storm water runoff during 100-year 24-hour storm events. The peak runoff for the developed conditions will not exceed the peak runoff rate of the existing conditions.

A Storm Water Pollution Prevention Plan (SWPPP) will be prepared prior to construction of the PEC. This plan will be utilized at the PEC site to control and minimize storm water during the construction of the facility. The plan will use BMPs such as stabilized construction entrances, silt fencing, berms, hay bales, and detention basins to control runoff from all construction areas.

Site Flood Issues

According to the Federal Emergency Management Agency (FEMA), a small portion of the site is within the 100-year flood plain of Los Gatos Creek. This portion of the site will not contain any structures. Also, this portion of the site will not be filled or graded to effect (raise) the existing surface elevation, thereby conforming with the Fresno County Ordinance Title 15. The remaining portion of the site upon which the plant structures will be constructed is above the 100-year flood plain.

Earthwork

Excavation work will consist of the removal, storage, and/or disposal of earth, sand, gravel, vegetation, organic matter, loose rock, boulders, and debris to the lines and grades necessary for construction. Materials suitable for backfill will be stockpiled at designated locations using proper erosion protection methods. Excess material will be removed from the site and disposed of at an acceptable location. If contaminated material is encountered during excavation, its disposal will comply with applicable laws, ordinances, regulations, and standards (LORS). The site is currently an agricultural area. Existing trees and topsoil will be removed. The trees will be shredded and used as mulch on nearby orchards by the landowner.

Graded areas will be smooth, compacted, free from irregular surface changes, and sloped to drain. Cut and fill slopes for permanent embankments will be designed to withstand horizontal ground accelerations for Seismic Zone 4. For slopes requiring soil reinforcement to resist seismic loading, geogrid reinforcement will be used for fills and soil nailing for cuts. Slopes for embankments will be no steeper than 2:1 (horizontal:vertical). The existing grade is fairly level.

Therefore, major cuts and fills are not anticipated. Earthwork will essentially be limited to that needed to ensure proper surface contour and soil compaction.

Excavation will include removal of unsuitable material and rocks. The bottom of an excavation will be examined for loose or soft areas. Such areas will be excavated fully and backfilled with compacted fill.

Backfilling will be done in layers of uniform, specified thickness. Soil in each layer will be properly moistened to facilitate compaction to achieve the specified density. To verify compaction, representative field density and moisture-content tests will be performed during compaction. Structural fill supporting foundations, roads, and parking areas will be compacted to at least 95 percent of the maximum dry density as determined by American Society for Testing Materials (ASTM) D-1557. Embankments, dikes, bedding for buried piping, and backfill surrounding structures will be compacted to a minimum of 90 percent of the maximum dry density. Backfill placed in remote and/or unsurfaced areas will be compacted to at least 85 percent of the maximum dry density.

Where fills are to be placed on subgrades sloped at 6:1 (horizontal:vertical) or greater, keys into the existing subgrade may be provided to help withstand horizontal seismic ground accelerations. The subgrades (original ground), subbases, and base courses of roads will be prepared and compacted in accordance with California Department of Transportation (Caltrans) standards. Testing will be in accordance with ASTM and Caltrans standards.

Electrical Interconnection

The new generation will be interconnected to the PG&E transmission grid through the facility's 230kV outdoor switchyard via a 230kV transmission line to the PG&E Panoche Substation. To accommodate the new generation by the four new combustion turbine generators, the Panoche Substation and the transmission system owned by PG&E may be upgraded in accordance with the final PG&E facility study report.

Panoche Substation Expansion

The project will interconnect to PG&E's existing Panoche Substation's 230kV bus. The 230kV conductor will exit from the northeast corner of the project site and run northeast approximately 300 feet to tie in to the Panoche Substation. There is limited space within the existing Panoche Substation, and PG&E will extend the existing 230kV bus. Approximately 250 feet by 435 feet of land on the south side of the existing 230kV bus will be acquired by PG&E to accommodate this expansion. The land to be acquired currently supports agricultural production.

Transmission Line Specifications

The onsite interconnection facilities will consist of an outdoor switchyard which includes:

- A transmission line strain bus

- Bus structures
- Transmission line dead end structure
- Line surge arresters
- High voltage disconnect switches
- High voltage circuit breakers
- Metering and relaying devices
- Foundations
- Ground grid
- Fencing
- Any other components necessary to connect the generators to the switchyard
- The switchyard design will be coordinated with PG&E as required. The new overhead transmission line from the switchyard to the substation will be 230kV.

Conductor

The generation-tie line connecting the project to the expanded existing Panoche Substation will be constructed using 795 aluminum conductor steel reinforced (ACSR) conductor or equivalent.

Ground Wire

The transmission line will have shield or ground wires in place. The location of the shield wires in relation to conductors shall be in accordance with best industry practices and determined by the surrounding terrain. The shield wire shall be extra high strength galvanized steel or copper-clad steel as determined by the location and the detailed design.

Route

The proposed transmission line will originate from the plant switchyard located on the north side of the site. The 230kV transmission line will exit from the northeast corner of the project site and run northeast approximately 300 feet to tie into the Panoche Substation.

Panoche Substation Interconnect

In order to interconnect to the Panoche Substation it is necessary for PG&E to extend the existing 230kV double busses on the south side of the substation outside the existing fence line by about 300 feet for two new 230kV bays, one for the relocation of the Gates-Panoche Line #1 and the other for the new generation-tie line. The relocation of the Gates-Panoche Line #1 and use of the existing spare bay are necessary to provide for the interconnection. The main ground grid will be expanded to cover the two new bays. Lighting and fencing for the new area will also be installed by PG&E.

Transmission Structures

The proposed 230kV transmission lines will be overhead conductor design with a transmission line span of 300 feet. There will be two dead-end take off structures. One structure will be at the originating outdoor switchyard located in the new facility and the other structure will be a dead end structure to terminate the incoming 230kV line at the PG&E Panoche Substation.

Types

The take off or the dead end structures will be H or A frame type. They will be 65 feet high with additional 15-foot lightning masts. The power conductor will be attached 50 feet from the ground and the shield wire will be attached at a height of 65 feet. There will be three additional structures in the facility outdoor 230kV switchyard to support the strain bus assembly.

Foundations

Foundations will be required for 230kV disconnect switches, 230kV circuit breakers, voltage and current transformers, strain bus termination structures, and outgoing dead end structure. The foundations will be drilled pier concrete foundations with the necessary anchor bolts.

Access to Structures

The entire interconnection phase of the project will be located within the confines of the generating facility outdoor switchyard and the PG&E substation. The transmission line will have only a 300-foot span. It will originate at the facility outdoor switchyard dead end structure and terminate at the Panoche Substation incoming dead end structure. No access to the electrical interconnection facilities will be required across any private property. The public will not have access to any portions of the transmission lines or the switchyard.

Wilson-Gregg Transmission Line Reconductoring

To effectively move this new generation of electricity, a portion of the existing Wilson-Gregg 230kV Line must be reconductored. The Wilson-Gregg 230kV Line related to the one-mile reconductoring is located immediately north of the Gregg Substation, north of the City of Fresno in Madera County between tower 101/674 and 102/681. This process will occur from the top down using helicopters to minimize ground disturbance and maximize safety. All material and equipment storage and staging will occur at the existing Gregg Substation located adjacent to the towers. Activities involved with the preparation of the towers include a staging area to assemble the tower extensions, preparation of the towers to take the tower extensions and installation of the tower extension. A landing location for the helicopter will be located inside the Gregg Substation. All assembled tower extensions, workers, materials and equipment/tools will be flown to the towers with a helicopter. Methods used to "install the new conductor" will require some ground vehicle(s) activity which will occur either in a developed orchard or on dirt access roads. These areas in the orchard or on the access road may (depending on the soil) require the laying down rock on top (a SWPPP measure) to move set up equipment to remove the old conductor and install the new conductor. Helicopters will once again be used to deliver workers, equipment/tools and materials to and from the towers. These activities are considered temporary impacts and will not require soil excavation or vegetation removal.

Natural Gas Supply Pipeline

The project includes a natural gas supply pipeline (lateral connection from trunk line and onsite). Natural gas will be delivered to the plant site from a connection to a PG&E trunk line. A new gas compressor, metering, and regulator station will be provided on the east side of the site. The gas will be metered by PG&E as it enters the project site. The gas will be compressed as required and directed to each CTG. Additional flow metering will be provided at each CTG. The piping will be routed to the aboveground gas metering and regulation station and either routed aboveground or belowground to the gas compressors. From the gas compressors the pipeline will be routed underground to each CTG. The gas piping system will be constructed of carbon steel materials suitable for the design pressures and temperatures. Isolation and control valves will be provided as required by design, operational, and safety requirements.

Pipeline Routes

The PEC project will require the construction of approximately 2,400 linear feet of offsite pipeline, up to 16-inches in diameter, to supply natural gas to the project site. The primary route runs north of the PG&E electrical substation along Panoche Road. An alternate route is under consideration which would be located to the south of the substation. Either route is technically acceptable.

Buried Pipe

Construction will primarily use an open trench method. The pipeline will be constructed of carbon steel in accordance with the American Petroleum Institute (API) specifications for gas pipelines or specifications of the ASTM. The pipe will have corrosion-protection coating that is either factory- or field-applied. Joints will be welded, inspected using x-ray, and wrapped with a corrosion-protection coating. Construction of the natural gas pipeline is described in the following subsections.

Trenching

The width of the trench is dependent on the soil type encountered and requirements of governing agencies. The optimal dimensions of the trench will be about 18 inches wide and 48 inches deep. For loose soil, a trench of up to 8 feet wide at the top and 2 feet wide at the bottom may be required. The pipeline will be buried with a minimum 36-inch cover. The excavated soil will be piled on one side of the trench and later used for backfilling after the pipe is installed in the trench.

Stringing

The pipe will be laid out (stringing) on wooden skids along the side of the open trench during installation.

Installation

Installation consists of:
• Welding, coating, and bending of pipe
• Laying sand or fine spoil on the trench floor
• Lowering the pipe string into the trench
Welding will meet the applicable API and ASTM standards and shall be performed by qualified welders. Welds will undergo radiographical inspection by an independent, qualified radiography contractor. All coatings will be checked for holidays and will be repaired before lowering the pipe into the trench.

Backfilling

Backfilling consists of returning excavated soil back into the trench around and on top of the pipe, and up to the original grade of the surface. The backfill will be compacted to protect the stability of the pipe and minimize subsequent subsidence.

Plating

Plating consists of covering any open trenches, for safety purposes, with solid rectangular plates in areas of foot or vehicular traffic at the end of a workday. Plywood plates can be used in areas of foot traffic and steel plates on areas of vehicular traffic.

Pneumatic Testing

Pneumatic testing consists of plugging both open ends of a pipeline that is to be tested, filling the pipe with air up to a pressure specified by code requirements, and maintaining the pressure for a period of time.

Clean up

Clean up consists of restoring the ground surface by removing construction debris, grading the surface to its original state, and replanting vegetation.

Commissioning

Commissioning consists of cleaning and drying the interior of the pipeline, purging air from the pipeline, and filling the pipeline with natural gas.

Safety

Safety consists of complying with all applicable California Occupational Safety and Health (CalOSHA), OSHA, and other regulations and standards as well as contractor's specific safety plans for the project, which will address specific pipeline safety issues.

Water Supply and Treatment

PEC process water will be supplied via two on-site production wells connected to a lower aquifer. Process water uses include fire protection water, plant service water, sanitary water, cooling tower makeup, combustion turbine NOx injection (after treatment), and combustion turbine inlet air evaporative cooler makeup (partly from treated water). The CTG injection water will be treated using a RO system, followed by trailer-mounted demineralizers.

These wells will also supply facility showers, sinks, toilets, eye wash stations, and safety showers in hazardous chemical areas. Signs will be posted to alert personnel that production well water is not for human consumption.

Facility Operations & Maintenance

This section discusses operation and maintenance procedures that will be followed by the PEC staff to ensure safe, reliable, and environmentally acceptable operation of the power plant, transmission system, and pipelines.

Power Plant Facility

The PEC is designed as a simple cycle; intermediately loaded peaking facility with four GE LMS100 CTG's. The PEC will require approximately 12 full time employees. Plant operations will be directed from a new control room. All system equipment will be controlled through a programmable logic control (PLC) and the project equipment will be integrated into this proven control system.

The plant will be operated to provide its maximum available electrical output during the periods when the demand for electricity is greatest. As an intermediate load and peaking facility, the plant is estimated to operate no more than 5,000 hours per year. The plant will be dispatched by PG&E in accordance with their economic dispatch procedures. The project equipment will be integrated with a PEC plant performance monitoring program that allows plant staff to make critical decisions as to when the equipment performance has deteriorated to the extent requiring corrective action. This program also allows the plant staff to accurately determine the cost of electrical production. This ability in conjunction with an experienced and adaptable staff will allow the plant to be operated and maintained in the most efficient method possible. Planned maintenance will be coordinated to coincide with periods of low power demand on the CAISO (independent system operator) system.

Transmission System Operation and Maintenance

PEC will be responsible for the maintenance, inspection, and normal operation of the new 300-foot 230kV interconnecting transmission line in agreement with PG&E and Independent System Operator (ISO) protocols. Operation of the electrical interconnection facilities will be locally controlled at the new generating plant. Operation may also be remotely monitored and controlled by PG&E via the PEC supervisory control and data acquisition system (SCADA). Control and protection equipment at the plant and within the PG&E switchyard will monitor and control the safe operation of the line, and will automatically trip the plant (or a portion of it) and/or the line in the event of a fault. The PEC will have continuous access to all of the electrical interconnection facilities in the event of an emergency.

The control, protection, and metering equipment for the interconnection will be tested for proper operation. The protection and metering equipment will be calibrated and tested approximately every 12 months in accordance with the PEC and PG&E procedures. Inspections of the transmission line and structures are anticipated to occur every 6 to 12 months. Periodic cleaning of the transmission line and switchyard insulators and bushings may be required to remove contamination. The cleaning will be performed based on visual inspections scheduled by plant and switchyard operating personnel. Washing operations will consist of spraying insulators with deionized water through high-pressure equipment mounted on a truck.

Pipelines

There are no water lines that leave the PEC property. A natural gas pipeline from PG&E Gas Line 2 to the project will be owned by PG&E. Operation and maintenance of the natural gas pipeline from the existing fuel gas supply lines will be performed by PG&E in accordance with applicable Federal Energy Regulatory Commission (FERC) and U.S. Department of Transportation (DOT) regulations. This piping system will receive periodic inspections as part of PG&E's pipeline maintenance program. Industrial wastewater will be discharged to the onsite deep well injection system. The connection to the system will be built, owned, and operated by the PEC.

Conservation Measures

Conservation measures are designed to benefit or promote the recovery of general and special status species as an integral part of the proposed action. These actions will be taken by the PEC to minimize or compensate for project effects on the kit fox. These conservation measures include actions taken prior to the initiation of consultation and actions which the PEC have committed to complete.

As part of the project, PEC proposes to implement a number of avoidance, minimization, and conservation measures that would be applicable and common to all species. These measures are intended to reduce, ameliorate, and/or avoid potential adverse effects on the kit fox. The avoidance and minimization measures that follow are expected to augment other project-related environmental commitments, best management practices (BMPs), and mitigation measures that would be required under separate Federal and State laws, regulations, and executive orders.

Impacts to kit fox habitat will be offset through the purchase of conservation credits at the Kreyenhagen Hills conservation bank. Total compensation has been determined based on the area permanently impacted (16.8 acres) at a ratio of 1.1:1, and 0.3 to 1 acres for areas temporarily impacted (9.0 acres).

The minimization and avoidance measures provided below are proposed as part of the proposed action. These measures are intended to address potential adverse affects on federally listed species that are known to occur within the study area or have the potential to occur. They have been developed through coordination with agency staff, including the Service, CDFG, and CEC.

1. Impacts to kit fox habitat will be offset through a contribution to a local conservation bank. Pursuant to discussions with Service, total compensation has been determined based on the area permanently impacted (16.8 acres) at a ratio of 1.1 to 1 acres and 0.3 to 1 acres for areas temporarily impacted (9.0 acres). This contribution will occur at Kreyenhagen Hills conservation bank, or by fee title acquisition or purchase of a conservation easement on a service-approved parcel, following all the requirements in *Selected Review Criteria for Conservation Banks and Section 7 Offsite Compensation April 11, 2006 (enclosed).*

2. Project-related vehicles shall observe a 20-mph speed limit in all project areas, except on county roads and State and Federal highways; this is particularly important at night when kit foxes are most active. To the extent possible, night-time construction should be minimized. Off-road traffic outside of designated project areas should be prohibited.

3. To prevent inadvertent entrapment of kit foxes or other animals during the construction phase of a project, all excavated, steep-walled holes or trenches more than 2 feet deep shall be covered at the close of each working day by plywood or similar materials, or provided with one or more escape ramps constructed of earth fill or wooden planks. Before such holes or trenches are filled, they should be thoroughly inspected for trapped animals. If at any time a trapped or injured kit fox is discovered, the procedures under number 13 of this section must be followed.

4. Kit foxes are attracted to den-like structures such as pipes and may enter stored pipe becoming trapped or injured. All construction pipes, culverts, or similar structures with a diameter of 4-inches or greater that are stored at a construction site for one or more overnight periods shall be thoroughly inspected for kit foxes before the pipe is subsequently buried, capped, or otherwise used or moved in any way. If a kit fox is discovered inside a pipe, that section of pipe should not be moved until the Service has been consulted. If necessary, and under the direct supervision of the biologist, the pipe may be moved once to remove it from the path of construction activity, until the fox has escaped.

5. All food-related trash items such as wrappers, cans, bottles, and food scraps shall be disposed of in closed containers and removed at least once a week from a construction or project site.
6. No firearms shall be allowed on the project site.
7. To prevent harassment, mortality of kit foxes or destruction of dens by dogs or cats, no pets will be permitted on project sites.
8. Use of rodenticides and herbicides in project areas will be restricted. This is necessary to prevent primary or secondary poisoning of kit foxes and the depletion of prey populations on which they depend. All uses of such compounds should observe label and other restrictions mandated by the U.S. Environmental Protection Agency, California Department of Food and Agriculture, and other State and Federal legislation, as well as additional project-related restrictions deemed necessary by the Service. If rodent control must be conducted, zinc phosphide should be used because of proven lower risk to kit fox.
9. A representative shall be appointed by the project proponent who will be the contact source for any employee or contractor who might inadvertently kill or injure a kit fox or who finds a dead, injured or entrapped individual. The representative will be identified during the employee education program. The representative's name and telephone number shall be provided to the Service.
10. An employee education program shall be conducted. The program will consist of a brief presentation by persons knowledgeable in kit fox biology and legislative protection to explain endangered species concerns to contractors, their employees, and military and agency personnel involved in the project. The program will include the following: a description of the kit fox and its habitat needs; a report of the occurrence of kit fox in the project area; an explanation of the status of the species and its protection under the Endangered Species Act; and a list of measures being taken to reduce impacts to the species during project construction and implementation. A fact sheet conveying this information should be prepared for distribution to the above-mentioned people and anyone else who may enter the project site. The program will be conducted in languages other than English, as appropriate.
11. Upon completion of the project, all areas subject to temporary ground disturbances, including storage and staging areas, temporary roads, pipeline corridors, etc. will be re-contoured if necessary, and revegetated to promote restoration of the area to pre-project conditions. An area subject to "temporary" disturbance means any area that is disturbed during the project, but that after project completion will not be subject to further disturbance and has the potential to be revegetated. Appropriate methods and plant species used to revegetate such areas should be determined on a site-specific basis in consultation with the Service, California Department of Fish and Game (CDFG), and revegetation experts.

12. In the case of trapped animals, escape ramps or structures should be installed immediately to allow the animal(s) to escape, or the Service should be contacted for advice.

13. Any contractor, employee, or military or agency personnel who inadvertently kills or injures a San Joaquin kit fox shall immediately report the incident to their representative. This representative shall contact the CDFG and the Service immediately in the case of a dead, injured or entrapped kit fox. The CDFG contact for immediate assistance is State Dispatch at (916) 445-0045. They will contact the local warden or biologist.

14. The Sacramento Fish and Wildlife Office and CDFG will be notified in writing within three working days of the accidental death or injury to a San Joaquin kit fox during project related activities. Notification must include the date, time, and location of the incident or of the finding of a dead or injured animal and any other pertinent information. The Service contact is the Chief of the Division of Endangered Species, at the addresses and telephone numbers given below. The CDFG contact is Mr. Ron Schlorff at 1416 9th Street, Sacramento, California 95814, (916) 654-4262.

15. Limits of grading and construction activities should be clearly delineated so that no vegetation outside the delineated grading limits would be disturbed by construction personnel or equipment. Project personnel will drive only on existing roads outside of construction limits.

16. PEC will implement the Best Management Practices identified in the project specific Storm Water Pollution Prevention Plan (SWPPP).

17. In order to comply with the Migratory Bird Treaty Act and relevant sections of the CDFG Code (e.g., 3503, 3503.4, 3504, 3505, et seq.), any vegetation clearing would take place outside of the typical avian nesting season (i.e., February 1st – August 31st), to the maximum extent practical. If this is not possible, prior to ground-disturbing activities, construction, and so forth within the study area, a qualified biologist will conduct and submit a migratory nesting bird and raptor survey report. A qualified biologist is an individual with sufficient education and field experience in local California ecology and biology to adequately identify local plant and wildlife species. The survey shall occur not more than 72 hours prior to initiation of Project activities and any occupied passerines and/or raptor nests occurring within or adjacent to the study area will be delineated. To the maximum extent practicable, a minimum buffer zone from occupied nests will be maintained during physical ground-disturbing activities. Once nesting has been determined to cease, the buffer may be removed.

18. PEC will retain the services of a Biological Monitor who will be responsible for overseeing project environmental protection measures. All encounters with listed species will be reported to the Biological Monitor, who will record the following information: species name; location (narrative and maps) and dates of observations; general condition and health, including injuries and state of healing; diagnostic markings, including identification numbers or markers; and locations moved from and to (if appropriate).

Status of the Species

San Joaquin kit fox

The San Joaquin kit fox was listed as an endangered species on March 11, 1967 (Service 1967) and was listed by the State of California as a threatened species on June 27, 1971. *The Recovery Plan for Upland Species of the San Joaquin Valley, California* (Recovery Plan) includes this canine (Service 1998).

In the San Joaquin Valley before 1930, the range of the kit fox extended from southern Kern County north to Tracy, San Joaquin County, on the west side, and near La Grange, Stanislaus County, on the east side (Grinnell *et al.* 1937; Service 1998). Historically, this species occurred in several San Joaquin Valley native plant communities. In the southernmost portion of the range, these communities included Valley Sink Scrub, Valley Saltbush Scrub, Upper Sonoran Subshrub Scrub, and Annual Grassland. Kit foxes also exhibit a capacity to utilize habitats that have been altered by man. The animals are present in many oil fields, grazed pasturelands, and "wind farms" (Cypher 2000). Kit foxes can inhabit the margins and fallow lands near irrigated row crops, orchards, and vineyards, and may forage occasionally in these agricultural areas (Service 1998). The kit fox seems to prefer more gentle terrain and decreases in abundance as terrain ruggedness increases (Grinnell *et al.* 1937; Morrell 1972; Warrick and Cypher 1998).

The kit fox is often associated with open grasslands, which form large contiguous blocks within the eastern portions of the range of the animal. The listed canine also utilizes oak savanna and some types of agriculture (e.g. orchards and alfalfa), although the long-term suitability of these habitats is unknown (Jensen 1972; Service 1998). In eastern Merced County, the lands between the urban corridor along Highway 99 and the open grasslands to the east are a mixture of orchards and annual crops, mostly alfalfa. Orchards occur in large contiguous blocks in the northwest portions of the study area and at scattered locations in the southwest portions. Orchards sometimes support prey species if the grounds are not manicured; however, denning potential is typically low and kit foxes can be more susceptible to coyotes predation within the orchards (Orloff 2000). Alfalfa fields provide an excellent prey base (Woodbridge 1987; Young 1989), and berms adjacent to alfalfa fields sometimes provide good denning habitat (Orloff 2000). Kit foxes often den adjacent to, and forage within, agricultural areas (Bell 1994; Scott-Graham 1994). Although agricultural areas are not traditional kit fox habitat and are often highly fragmented, they can offer sufficient prey resources and denning potential to support small numbers of kit foxes.

Adult kit foxes are usually solitary during late summer and fall. In September and October, adult females begin to excavate and enlarge natal dens (Morrell 1972), and adult males join the females in October or November (Morrell 1972). Typically, pups are born between February and late March following a gestation period of 49 to 55 days (Egoscue 1962; Morrell 1972; Spiegel and Tom 1996; Service 1998). Mean litter sizes reported for San Joaquin kit foxes include 2.0 on the Carrizo Plain (White and Ralls 1993), 3.0 at Camp Roberts (Spencer *et al.* 1992), 3.7 in the Lokern area (Spiegel and Tom 1996), and 3.8 at the Naval Petroleum Reserve (Cypher *et al.* 2000). Pups appear above ground at about age 3-4 weeks, and are weaned at age 6-8 weeks.

Reproductive rates, the proportion of females bearing young, of adult kit foxes vary annually with environmental conditions, particularly food availability. Annual rates range from 0-100%, and reported mean rates include 61% at the Naval Petroleum Reserve (Cypher *et al.* 2000), 64% in the Lokern area (Spiegel and Tom 1996), and 32% at Camp Roberts (Spencer *et al.* 1992). Although some yearling female kit foxes will produce young, most do not reproduce until age 2 years (Spencer et al. 1992; Spiegel and Tom 1996; Cypher *et al.* 2000). Some young of both sexes, but particularly females may delay dispersal, and may assist their parents in raising in the following year's litter of pups (Spiegel and Tom 1996). The young kit foxes begin to forage for themselves at about four to five months of age (Koopman *et al.* 2000; Morell 1972).

Although most young kit foxes disperse less than 5 miles (Scrivner *et al.* 1987a), dispersal distances of up to 76.3 miles have been documented for the kit fox (Scrivner *et al.* 1993; Service 1998). Dispersal can be through disturbed habitats, including agricultural fields, and across highways and aqueducts. The age at dispersal ranges from 4-32 months (Cypher 2000). Among juvenile kit foxes surviving to July 1 at the Naval Petroleum Reserve, 49% of the males dispersed from natal home ranges while 24% of the females dispersed (Koopman *et al.* 2000). Among dispersing kit foxes, 87% did so during their first year of age. Most, 65.2%, of the dispersing juveniles at the Naval Petroleum Reserve died within 10 days of leaving their natal home den (Koopman *et al.* 2000). Some kit foxes delay dispersal and may inherit their natal home range.

Kit foxes are reputed to be poor diggers, and their dens are usually located in areas with loose-textured, friable soils (Morrell 1972; O'Farrell 1984). However, the depth and complexity of their dens suggest that they possess good digging abilities, and kit fox dens have been observed on a variety of soil types (Service 1998). Some studies have suggested that where hardpan layers predominate, kit foxes create their dens by enlarging the burrows of California ground squirrels (*Spermophilus beecheyi*) or badgers (*Taxidea taxus*)(Jensen 1972; Morrell 1972; Orloff *et al.* 1986). In parts of their range, particularly in the foothills, kit foxes often use ground squirrel burrows for dens (Orloff *et al.* 1986). Kit fox dens are commonly located on flat terrain or on the lower slopes of hills. About 77 percent of all kit fox dens are at or below midslope (O'Farrell 1983), with the average slope at den sites ranging from 0 to 22 degrees (California Department of Fish and Game 1980; O'Farrell 1983; Orloff *et al.* 1986). Natal and pupping dens are generally found in flatter terrain. Common locations for dens include washes, drainages, and roadside berms. Kit foxes also commonly den in human-made structures such as culverts and pipes (O'Farrell 1983; Spiegel 1996a).

Natal and pupping dens may include from two to 18 entrances and are usually larger than dens that are not used for reproduction (O'Farrell *et al.* 1980; O'Farrell and McCue 1981). Natal dens may be reused in subsequent years (Egoscue 1962). It has been speculated that natal dens are located in the same location as ancestral breeding sites (O'Farrell 1983). Active natal dens are generally 1.2 to 2 miles from the dens of other mated kit fox pairs (Egoscue 1962; O'Farrell and Gilbertson 1979). Natal and pupping dens usually can be identified by the presence of scat, prey remains, matted vegetation, and mounds of excavated soil (i.e. ramps) outside the dens (O'Farrell 1983). However, some active dens in areas outside the valley floor often do not show evidence of use (Orloff *et al.* 1986). During telemetry studies of kit foxes in the northern portion of their range, 70 percent of the dens that were known to be active showed no sign of use (e.g., tracks, scats, ramps, or prey remains)(Orloff *et al.* 1986). In another more recent study in the Coast Range, 79 percent of active kit fox dens lacked evidence of recent use other than signs of recent excavation (Jones and Stokes Associates 1997).

A kit fox can use more than 100 dens throughout its home range, although on average, an animal will use approximately 12 dens a year for shelter and escape cover (Cypher *et al.* 2001). Kit foxes typically use individual dens for only brief periods, often for only one day before moving to another den (Ralls *et al.* 1990). Possible reasons for changing dens include infestation by ectoparasites, local depletion of prey, or avoidance of coyotes (*Canis latrans*). Kit foxes tend to use dens that are located in the same general area, and clusters of dens can be surrounded by hundreds of hectares of similar habitat devoid of other dens (Egoscue 1962). In the southern San Joaquin Valley, kit foxes were found to use up to 39 dens within a denning range of 320 to 482 acres (Morrell 1972). An average den density of one den per 69 to 92 acres was reported by O'Farrell (1984) in the southern San Joaquin Valley.

Dens are used by kit foxes for temperature regulation, shelter from adverse environmental conditions, and escape from predators. Kit foxes excavate their own dens, use those constructed by other animals, and use human-made structures (culverts, abandoned pipelines, and banks in sumps or roadbeds). Kit foxes often change dens and may use many dens throughout the year; however, evidence that a den is being used by kit foxes may be absent. San Joaquin kit foxes have multiple dens within their home range and individual animals have been reported to use up to 70 different dens (Hall 1983). At the Naval Petroleum Reserve, individual kit foxes used an average of 11.8 dens per year (Koopman *et al.* 1998). Den switching by the kit fox may be a function of predator avoidance, local food availability, or external parasite infestations (e.g., fleas) in dens (Egoscue 1956).

The diet of the kit fox varies geographically, seasonally, and annually, based on temporal and spatial variation in abundance of potential prey. In the portion of their geographic range that includes Merced County, known prey species of the kit fox include white-footed mice (*Peromyscus* spp.), insects, California ground squirrels, kangaroo rats (*Dipodomys* spp.), San Joaquin antelope squirrels, black-tailed hares (*Lepus californicus*), and chukar (*Alectoris chukar*) (Jensen 1972, Archon 1992), listed in approximate proportion of occurrence in fecal samples. Kit foxes also prey on desert cottontails (*Sylvilagus audubonii)*, ground-nesting birds, and pocket mice (*Perognathus* spp.).

The diets and habitats selected by coyotes and kit foxes living in the same areas are often quite similar. Hence, the potential for resource competition between these species may be quite high when prey resources are scarce such as during droughts, which are quite common in semi-arid, central California. Competition for resources between coyotes and kit foxes may result in kit fox mortalities. Coyote-related injuries accounted for 50-87 per cent of the mortalities of radio collared kit foxes at Camp Roberts, the Carrizo Plain Natural Area, the Lokern Natural Area, and the Naval Petroleum Reserves (Cypher and Scrivner 1992; Standley *et al.* 1992).

Kit foxes are primarily nocturnal, although individuals are occasionally observed resting or playing (mostly pups) near their dens during the day (Grinnell *et al.* 1937). Kit foxes occupy home ranges that vary in size from 1.7 to 4.5 square miles (White and Ralls 1993). A mated pair of kit foxes and their current litter of pups usually occupy each home range. Other adults, usually offspring from previous litters, also may be present (Koopman *et al.* 2000), but individuals often move independently within their home range (Cypher 2000). Average distances traveled each night range from 5.8 to 9.1 miles and are greatest during the breeding season (Cypher 2000).

Kit foxes maintain core home range areas that are exclusive to mated pairs and their offspring (White and Ralls 1993, Spiegel 1996b, White and Garrott 1997). This territorial spacing behavior eventually limits the number of foxes that can inhabit an area owing to shortages of available space and per capita prey. Hence, as habitat is fragmented or destroyed, the carrying capacity of an area is reduced and a larger proportion of the population is forced to disperse. Increased dispersal generally leads to lower survival rates and, in turn, decreased abundance because greater than 65 percent of dispersing juvenile foxes die within 10 days of leaving their natal range (Koopman *et al.* 2000).

Estimates of fox density vary greatly throughout its range, and have been reported as high as 1.3 animals per square mile in optimal habitats in good years (Service 1998). At the Elk Hills in Kern County, density estimates varied from 1.86 animals per square mile in the early 1980s to 0.03 animals per square mile in 1991 (Service 1998). Kit fox home ranges vary in size from approximately 1 to 12 square miles (Spiegel *et al.* 1996; Service 1998). Knapp (1978) estimated that a home range in agricultural areas is approximately 1 square mile. Individual home ranges overlap considerably, at least outside the core activity areas (Morrell 1972; Spiegel *et al.* 1996). Mean annual survival rates reported for adult San Joaquin kit foxes include 0.44 at the Naval Petroleum Reserve (Cypher *et al.* 2000), 0.53 at Camp Roberts (Standley *et al.* 1992), 0.56 at the Lokern area (Spiegel and Disney 1996), and 0.60 on the Carrizo Plain (Ralls and White 1995). However, survival rates widely vary among years (Spiegel and Disney 1996; Cypher *et al.* 2000). Mean survival rates for juvenile San Joaquin kit foxes (<1 year old) are lower than rates for adults. Survival to age 1 year was 0.14 at the Naval Petroleum Reserve (Cypher *et al.* 2000), 0.20 at Camp Roberts (Standley *et al.* 1992), and 0.21 on the Carrizo Plain (Ralls and White 1995). For both adults and juveniles, survival rates of males and females are similar. San Joaquin kit foxes may live to ten years in captivity (McGrew 1979) and 8 years in the wild (Berry et al. 1987), but most kit foxes do not live past 2-3 years of age.

The status (i.e., distribution, abundance) of the kit fox has decreased since its listing in 1967. This trend is reasonably certain to continue into the foreseeable future unless measures to protect, sustain, and restore suitable habitats, and alleviate other threats to their survival and recovery, are implemented. Threats that are seriously affecting kit foxes are described in further detail in the following paragraphs.

Loss of Habitat

Less than 20 percent of the habitat within the historical range of the kit fox remained when the subspecies was listed as federally-endangered in 1967, and there has been a substantial net loss of habitat since that time. Historically, San Joaquin kit foxes occurred throughout California's Central Valley and adjacent foothills. Extensive land conversions in the Central Valley began as early as the mid-1800s with the Arkansas Reclamation Act. By the 1930's, the range of the kit fox had been reduced to the southern and western parts of the San Joaquin Valley (Grinnell *et al.* 1937). The primary factor contributing to this restricted distribution was the conversion of native habitat to irrigated cropland, industrial uses (e.g., hydrocarbon extraction), and urbanization (Laughrin 1970, Jensen 1972; Morrell 1972, 1975). Approximately one-half of the natural communities in the San Joaquin Valley were tilled or developed by 1958 (Service 1980).

This rate of loss accelerated following the completion of the Central Valley Project and the State Water Project, which diverted and imported new water supplies for irrigated agriculture (Service 1995). Approximately 1.97 million acres of habitat, or about 66,000 acres per year, were converted in the San Joaquin region between 1950 and 1980 (California Department of Forestry and Fire Protection 1988). The counties specifically noted as having the highest wildland conversion rates included Kern, Tulare, Kings and Fresno, all of which are occupied by kit foxes. From 1959 to 1969 alone, an estimated 34 percent of natural lands were lost within the then-known kit fox range (Laughrin 1970).

By 1979, only approximately 370,000 acres out of a total of approximately 8.5 million acres on the San Joaquin Valley floor remained as non-developed land (Williams 1985, Service 1980). Data from the CDFG (1985) and Service file information indicate that between 1977 and 1988, essential habitat for the blunt-nosed leopard lizard, a species that occupies habitat that is also suitable for kit foxes, declined by about 80 percent – from 311,680 acres to 63,060 acres, an average of about 22,000 acres per year (Biological Opinion for the Interim Water Contract Renewal, Ref. No. 1-1-00-F-0056, February 29, 2000). Virtually all of the documented loss of essential habitat was the result of conversion to irrigated agriculture.

During 1990 to 1996, a gross total of approximately 71,500 acres of habitat were converted to farmland in 30 counties (total area 23.1 million acres) within the Conservation Program Focus area of the Central Valley Project. This figure includes 42,520 acres of grazing land and 28,854 acres of "other" land, which is predominantly comprised of native habitat. During this same time period, approximately 101,700 acres were converted to urban land use within the Conservation Program Focus area (California Department of Conservation 1994, 1996, 1998). This figure includes 49,705 acres of farmland, 20,476 acres of grazing land, and 31,366 acres of "other" land, which is predominantly comprised of native habitat. Because these assessments included a substantial portion of the Central Valley and adjacent foothills, they provide the best scientific and commercial information currently available regarding the patterns and trends of land conversion within the kit fox's geographic range.

In summary, more than one million acres of suitable habitat for kit foxes have been converted to agricultural, municipal, or industrial uses since the listing of the kit fox. In contrast, less than 500,000 acres have been preserved or are subject to community-level conservation efforts designed, at least in part, to further the conservation of the kit fox (Service 1998).

Land conversions contribute to declines in kit fox abundance through direct and indirect mortalities, displacement, reduction of prey populations and denning sites, changes in the distribution and abundance of larger canids that compete with kit foxes for resources, and reductions in carrying capacity. Kit foxes may be buried in their dens during land conversion activities (C. Van Horn, Endangered Species Recovery Program, Bakersfield, personal communication to S. Jones, Fish and Wildlife Service, Sacramento, 2000), or permanently displaced from areas where structures are erected or the land is intensively irrigated (Jensen 1972, Morrell 1975). Furthermore, even moderate fragmentation or loss of habitat may significantly impact the abundance and distribution of kit foxes. Capture rates of kit foxes at the Naval Petroleum Reserve in Elk Hills were negatively associated with the extent of oil-field development after 1987 (Warrick and Cypher 1998). Likewise, the California Energy Commission found that the relative abundance of kit foxes was lower in oil-developed habitat than in nearby undeveloped habitat on the Lokern (Spiegel 1996a). Researchers from both studies inferred that the most significant effect of oil development was the lowered carrying capacity for populations of both foxes and their prey species owing to the changes in habitat characteristics or the loss and fragmentation of habitat (Spiegel 1996b, Warrick and Cypher 1998).

Dens are essential for the survival and reproduction of kit foxes that use them year-round for shelter and escape, and in the spring for rearing young. Hence, kit foxes generally have dozens of dens scattered throughout their territories. However, land conversion reduces the number of typical earthen dens available to kit foxes. For example, the average density of typical, earthen kit fox dens at the Naval Hills Petroleum Reserve was negatively correlated with the intensity of petroleum development (Zoellick *et al.* 1987), and almost 20 percent of the dens in developed areas were found to be in well casings, culverts, abandoned pipelines, oil well cellars, or in the banks of sumps or roads (Service 1983). These results are important because the California Energy Commission found that, even though kit foxes frequently used pipes and culverts as dens in oil-developed areas of western Kern County, only earthen dens were used to birth and wean pups (Spiegel 1996b). Similarly, kit foxes in Bakersfield use atypical dens, but have only been found to rear pups in earthen dens (P. Kelly, Endangered Species Recovery Program, Fresno, personal communication to P. White, Fish and Wildlife Service, Sacramento, April 6, 2000). Hence, the fragmentation of habitat and destruction of earthen dens could adversely affect the reproductive success of kit foxes. Furthermore, the destruction of earthen dens may also affect kit fox survival by reducing the number and distribution of escape refuges from predators.

Land conversions and associated human activities can lead to widespread changes in the availability and composition of mammalian prey for kit foxes. For example, oil field disturbances in western Kern County have resulted in shifts in the small mammal community from the primarily granivorous species that are the staple prey of kit foxes (Spiegel 1996b), to species adapted to early successional stages and disturbed areas (e.g., California ground squirrels)(Spiegel 1996a). Because more than 70 percent of the diets of kit foxes usually consist of abundant leporids (*Lepus*, *Sylvilagus*) and rodents (e. g., *Dipodomys* spp.), and kit foxes often continue to feed on their staple prey during ephemeral periods of prey scarcity, such changes in the availability and selection of foraging sites by kit foxes could influence their reproductive rates, which are strongly influenced by food supply and decrease during periods of prey scarcity (White and Garrott 1997, 1999).

Extensive habitat destruction and fragmentation have contributed to smaller, more-isolated populations of kit foxes. Small populations have a higher probability of extinction than larger populations because their low abundance renders them susceptible to stochastic (i.e., random) events such as high variability in age and sex ratios, and catastrophes such as floods, droughts, or disease epidemics (Lande 1988, Frankham and Ralls 1998, Saccheri *et al.* 1998). Similarly, isolated populations are more susceptible to extirpation by accidental or natural catastrophes because their recolonization has been hampered. These chance events can adversely affect small, isolated populations with devastating results. Extirpation can even occur when the members of a small population are healthy, because whether the population increases or decreases in size is less dependent on the age-specific probabilities of survival and reproduction than on raw chance (sampling probabilities). Owing to the probabilistic nature of extinction, many small populations will eventually lose out and go extinct when faced with these stochastic risks (Caughley and Gunn 1995).

Oil fields in the southern half of the San Joaquin Valley also continue to be an area of expansion and development activity. This expansion is reasonably certain to increase in the near future owing to market-driven increases in the price of oil. The cumulative and long-term effects of oil extraction activities on kit fox populations are not fully known, but recent studies indicate that moderate- to high-density oil fields may contribute to a decrease in carrying capacity for kit foxes owing to habitat loss or changes in habitat characteristics (Spiegel 1996b, Warrick and Cypher 1998). There are no limiting factors or regulations that are likely to retard the development of additional oil fields. Hence, it is reasonably certain that development will continue to destroy and fragment kit fox habitat into the foreseeable future.

Competitive Interactions with Other Canids

Several species prey upon kit foxes. Predators (such as coyotes, bobcats, non-native red foxes, badgers, and golden eagles [*Aquila chrysaetos*]) will kill kit foxes. Badgers, coyotes, and red foxes also may compete for den sites (Service 1998). The diets and habitats selected by coyotes and kit foxes living in the same areas are often quite similar (Cypher and Spencer 1998). Hence, the potential for resource competition between these species may be quite high when prey resources are scarce such as during droughts (which are quite common in semi-arid, central California). Land conversions and associated human activities have led to changes in the distribution and abundance of coyotes, which compete with kit foxes for resources.

Coyotes occur in most areas with abundant populations of kit foxes and, during the past few decades, coyote abundance has increased in many areas owing to a decrease in ranching operations, favorable landscape changes, and reduced control efforts (Orloff *et al.* 1986, Cypher and Scrivner 1992, White and Ralls 1993, White *et al.* 1995). Coyotes may attempt to lessen resource competition with kit foxes by killing them. Coyote-related injuries accounted for 50-87 percent of the mortalities of radio collared kit foxes at Camp Roberts, the Carrizo Plain Natural Area, the Lokern Natural Area, and the Naval Petroleum Reserves (Cypher and Scrivner 1992, Standley *et al.* 1992, Ralls and White 1995, Spiegel 1996b). Coyote-related deaths of adult foxes appear to be largely additive (i.e., in addition to deaths caused by other mortality factors such as disease and starvation) rather than compensatory (i.e., tending to replace deaths due to other mortality factors; White and Garrott 1997). Hence, the survival rates of adult foxes decrease significantly as the proportion of mortalities caused by coyotes increase (Cypher and Spencer 1998, White and Garrott 1997), and increases in coyote abundance may contribute to significant declines in kit fox abundance (Cypher and Scrivner 1992, Ralls and White 1995, White *et al.* 1996). There is some evidence that the proportion of juvenile foxes killed by coyotes increases as fox density increases (White and Garrott 1999). This density-dependent relationship would provide a feedback mechanism that reduces the amplitude of kit fox population dynamics and keeps foxes at lower densities than they might otherwise attain. In other words, coyote-related mortalities may dampen or prevent fox population growth, and accentuate, hasten, or prolong population declines.

Land-use changes also contributed to the expansion of nonnative red foxes into areas inhabited by kit foxes. Historically, the geographic range of the red fox did not overlap with that of the San Joaquin kit fox. By the 1970's, however, introduced and escaped red foxes had established breeding populations in many areas inhabited by kit foxes (Lewis *et al.* 1993). The larger and more aggressive red foxes are known to kill kit foxes (Ralls and White 1995), and could displace them, as has been observed in the arctic when red foxes expanded into the ranges of smaller arctic foxes (Hersteinsson and Macdonald 1982). The increased abundance and distribution of nonnative red foxes will also likely adversely affect the status of kit foxes because they are closer morphologically and taxonomically, and would likely have higher dietary overlap than coyotes; potentially resulting in more intense competition for resources. Two documented deaths of kit foxes due to red foxes have been reported (Ralls and White 1995), and red foxes appear to be displacing kit foxes in the northwestern part of their range (Lewis *et al.* 1993). At Camp Roberts, red foxes have usurped several dens that were used by kit foxes during previous years (California Army National Guard, Camp Roberts Environmental Office, unpubl. data). In fact, opportunistic observations of red foxes in the cantonment area of Camp Roberts have increased 5-fold since 1993, and no kit foxes have been sighted or captured in this area since October 1997. Also, a telemetry study of sympatric red foxes and kit foxes in the Lost Hills area has detected spatial segregation between these species, suggesting that kit foxes may avoid or be excluded from red fox-inhabited areas (P. Kelly, Endangered Species Recovery Program, Fresno, pers. comm. to P. White, Fish and Wildlife Service, Sacramento, April 6, 2000). Such avoidance would limit the resources available to local populations of kit foxes and possibly result in decreased fox abundance and distribution.

Disease

Wildlife diseases do not appear to be a primary mortality factor that consistently limits kit fox populations throughout their range (McCue and O'Farrell 1988, Standley and McCue 1992). However, central California has a high incidence of wildlife rabies cases (Schultz and Barrett 1991), and high seroprevalences of canine distemper virus and canine parvovirus indicate that kit fox populations have been exposed to these diseases (McCue and O'Farrell 1988; Standley and McCue 1992). Hence, disease outbreaks could potentially cause substantial mortality or contribute to reduced fertility in seropositive females, as was noted in closely-related swift foxes (*Vulpes velox*).

For example, there are some indications that rabies virus may have contributed to a catastrophic decrease in kit fox abundance at Camp Roberts, San Luis Obispo County, California, during the early 1990's. San Luis Obispo County had the highest incidence of wildlife rabies cases in California during 1989 to 1991, and striped skunks (*Mephitis mephitis*) were the primary vector (Barrett 1990, Schultz and Barrett 1991, Reilly and Mangiamele 1992). A rabid skunk was trapped at Camp Roberts during 1989 and two foxes were found dead due to rabies in 1990 (Standley *et al.* 1992). Captures of kit foxes during annual live trapping sessions at Camp Roberts decreased from 103 to 20 individuals during 1988 to 1991. Captures of kit foxes were positively correlated with captures of skunks during 1988 to 1997; suggesting that some factor(s) such as rabies virus was contributing to concurrent decreases in the abundances of these species. Also, captures of kit foxes at Camp Roberts were negatively correlated with the proportion of skunks that were rabid when trapped by County Public Health Department personnel two years previously. These data suggest that a rabies outbreak may have occurred in the skunk population and spread into the fox population. A similar time lag in disease transmission and subsequent population reductions was observed in Ontario, Canada, although in this instance the transmission was from red foxes to striped skunks (MacDonald and Voigt 1985).

Pesticides and Rodenticides

Pesticides and rodenticides pose a threat to kit foxes through direct or secondary poisoning. Kit foxes may be killed if they ingest rodenticide in a bait application, or if they eat a rodent that has consumed the bait. Even sublethal doses of rodenticides may lead to the death of these animals by impairing their ability to escape predators or find food. Pesticides and rodenticides may also indirectly affect the survival of kit foxes by reducing the abundances of their staple prey species. For example, the California ground squirrel, which is the staple prey of kit foxes in the northern portion of their range, was thought to have been eliminated from Contra Costa County in 1975, after extensive rodent eradication programs. Field observations indicated that the long-term use of ground squirrel poisons in this county severely reduced kit fox abundance through secondary poisoning and the suppression of populations of its staple prey (Orloff *et al.* 1986).

Kit foxes occupying habitats adjacent to agricultural lands are also likely to come into contact with insecticides applied to crops owing to runoff or aerial drift. Kit foxes could be affected through direct contact with sprays and treated soils, or through consumption of contaminated prey. Data from the California Department of Pesticide Regulation indicate that acephate, aldicarb, azinphos methyl, bendiocarb, carbofuran, chlorpyrifos, endosulfan, s-fenvalerate, naled, parathion, permethrin, phorate, and trifluralin are used within one mile of kit fox habitat. A wide variety of crops (alfalfa, almonds, apples, apricots, asparagus, avocados, barley, beans, beets, bok choy, broccoli, cantaloupe, carrots, cauliflower, celery, cherries, chestnuts, chicory, Chinese cabbage, Chinese greens, Chinese radish, collards, corn, cotton, cucumbers, eggplants, endive, figs, garlic, grapefruit, grapes, hay, kale, kiwi fruit, kohlrabi, leeks, lemons, lettuce, melons, mustard, nectarines, oats, okra, olives, onions, oranges, parsley, parsnips, peaches, peanuts, pears, peas, pecans, peppers, persimmons, pimentos, pistachios, plums, pomegranates, potatoes, prunes, pumpkins, quinces, radishes, raspberries, rice, safflower, sorghum, spinach, squash, strawberries, sugar beets, sweet potatoes, Swiss chard, tomatoes, walnuts, watermelons, and wheat), as well as buildings, Christmas tree plantations, commercial/industrial areas, greenhouses, nurseries, landscape maintenance, ornamental turf, rangeland, rights of way, and uncultivated agricultural and non-agricultural land, occur in close proximity to kit fox habitat.

Efforts have been underway to reduce the risk of rodenticides to kit foxes (Service 1993). The Federal government began controlling the use of rodenticides in 1972 with a ban of Compound 1080 on Federal lands pursuant to Executive Order. Above-ground application of strychnine within the geographic ranges of listed species was prohibited in 1988. A July 28, 1992, biological opinion regarding the Animal Damage Control (now known as Wildlife Services) Program by the U.S. Department of Agriculture found that this program was likely to jeopardize the continued existence of the kit fox owing to the potential for rodent control activities to take the fox. As a result, several reasonable and prudent measures were implemented, including a ban on the use of M-44 devices, toxicants, and fumigants within the recognized occupied range of the kit fox. Also, the only chemical authorized for use by Wildlife Services within the occupied range of the kit fox was zinc phosphide, a compound known to be minimally toxic to kit foxes (Service 1993).

Despite these efforts, the use of other pesticides and rodenticides still pose a significant threat to the kit fox, as evidenced by the death of 2 kit foxes at Camp Roberts in 1992 owing to secondary poisoning from chlorophacinone applied as a rodenticide, (Berry *et al.* 1992, Standley *et al.* 1992). Also, the livers of 3 foxes that were recovered in the City of Bakersfield during 1999 were found to contain detectable residues of the anticoagulant rodenticides chlorophacinone, brodifacoum, and bromadiolone (California Department of Fish and Game 1999).

To date, no specific research has been conducted on the effects of different pesticide or rodent control programs on the kit fox (Service 1998). This lack of information is problematic because Williams (in lit., 1989) documented widespread pesticide use in known kit fox and Fresno kangaroo rat habitat adjoining agricultural lands in Madera County. In a separate report, Williams (in lit., 1989) documented another case of pesticide use near Raisin City, Fresno County, where treated grain was placed within an active Fresno kangaroo rat precinct. Also, farmers have been allowed to place bait on Bureau of Reclamation property to maximize the potential for killing rodents before they entered adjoining fields (Biological Opinion for the Interim Water Contract Renewal, Ref. No. 1-1-00-F-0056, February 29, 2000).
A September 22, 1993, biological opinion issued by the Service to the Environmental Protection Agency (EPA) regarding the regulation of pesticide use (31 registered chemicals) through administration of the Federal Insecticide, Fungicide, and Rodenticide Act found that use of the following chemicals would likely jeopardize the continued existence of the kit fox: (1) aluminum and magnesium phosphide fumigants; (2) chlorophacinone anticoagulants; (3) diphacinone anticoagulants; (4) pival anticoagulants; (5) potassium nitrate and sodium nitrate gas cartridges; and (6) sodium cyanide capsules (Service 1993). Reasonable and prudent alternatives to avoid jeopardy included restricting the use of aluminum/magnesium phosphide, potassium/sodium nitrate within the geographic range of the kit fox to qualified individuals, and prohibiting the use of chlorophacinone, diphacinone, pival, and sodium cyanide within the geographic range of the

kit fox, with certain exceptions (e.g., agricultural areas that are greater than 1 mile from any kit fox habitat)(Service 1999).

Endangered Species Act Section 9 Violations and Noncompliance with the Terms and Conditions of Existing Biological Opinions

The intentional or unintentional destruction of areas occupied by kit foxes is an issue of serious concern. Section 9 of the Act prohibits the "take" (e.g., harm, harass, pursue, injure, kill) of federally-listed wildlife species. "Harm" (i.e., "take") is further defined to include habitat modification or degradation that kills or injures wildlife by impairing essential behavioral patterns including breeding, feeding, or sheltering. Congress established two provisions (under sections 7 and 10 of the Act) that allow for the "incidental take" of listed species of wildlife by Federal agencies, non-Federal government agencies, and private interests. Incidental take is defined as "incidental to, and not the purpose of, the carrying out of an otherwise lawful activity." Such take requires a permit from the Secretary of the Interior that anticipates a specific level of take for each listed species. If no permit is obtained for the incidental take of listed species, the individuals or entities responsible for these actions could be liable under the enforcement provisions of potential section 9 of the Act if any unauthorized take occurs. Nevertheless, the Service is aware of numerous instances of conversion of fox habitat to agricultural, residential, and commercial purposes throughout the San Joaquin Valley.

Risk of Chance Extinction Owing to Small Population Size, Isolation, and High Natural Fluctuations in Abundance

Historically, kit foxes may have existed in a metapopulation structure of core and satellite populations, some of which periodically experienced local extinctions and recolonization (Service 1998). Today's populations exist in an environment drastically different from the historic one, however, and extensive habitat fragmentation will result in geographic isolation, smaller population sizes, and reduced genetic exchange among populations; all of which increase the vulnerability of kit fox populations to extirpation. Populations of kit foxes are extremely susceptible to the risks associated with small population size and isolation because they are characterized by marked instability in population density. For example, the relative abundance of kit foxes at the Naval Petroleum Reserves, California, decreased 10-fold during 1981 to 1983, increased 7-fold during 1991 to 1994, and then decreased 2-fold during 1995 (Cypher and Scrivner 1992, Cypher and Spencer 1998).

Many populations of kit fox are at risk of chance extinction owing to small population size and isolation. This risk has been prominently illustrated during recent, drastic declines in the populations of kit foxes at Camp Roberts and Fort Hunter Liggett. Captures of kit foxes during annual live trapping sessions at Camp Roberts decreased from 103 to 20 individuals during 1988 to 1991. This decrease continued through 1997 when only three kit foxes were captured (White *et al.* 2000). A similar decrease in kit fox abundance occurred at nearby Fort Hunter Liggett, and only 2 kit foxes have been observed on this installation since 1995 (L. Clark, Wildlife Biologist, Fort Hunter Liggett, pers. comm. to P. White, Service, Sacramento, February 15, 2000). It is unlikely that the current low abundances of kit foxes at Camp Roberts and Fort Hunter Liggett will increase substantially in the near future owing to the limited potential for recruitment. The chance of substantial immigration is low because the nearest core population on the Carrizo Plain is distant (greater than 16 miles) and separated from these installations by barriers to kit fox movement such as roads, developments, and irrigated agricultural areas. Also, there is a relatively high abundance of sympatric predators and competitors on these installations that contribute to low survival rates for kit foxes and, as a result, may limit population growth (White *et al.* 2000). Hence, these populations may be on the verge of extinction.

The destruction and fragmentation of habitat could also eventually lead to reduced genetic variation in populations of kit foxes that are small and geographically isolated. Historically, kit foxes likely existed in a metapopulation structure of core and satellite populations, some of which periodically experienced local extinctions and recolonization (Service 1998). Preliminary genetic assessments indicate that historic gene flow among populations was quite high, with effective dispersal rates of at least one to 4 dispersers per generation (M. Schwartz, University of Montana, Missoula, pers. comm. on March 23, 2000, to P. White, Service, Sacramento, California). This level of genetic dispersal should allow for local adaptation while preventing the loss of any rare alleles. Based on these results, it is likely that northern populations of kit foxes were once panmictic (i.e., randomly mating in a genetic sense), or nearly so, with southern populations. In other words, there were no major barriers to dispersal among populations.

Current levels of gene flow also appear to be adequate, however, extensive habitat loss and fragmentation continues to form more or less geographically distinct populations of foxes, which could potentially reduce genetic exchange among them. An increase in inbreeding and the loss of genetic variation could increase the extinction risk for small, isolated populations of kit foxes by interacting with demography to reduce fecundity, juvenile survival, and lifespan (Lande 1988, Frankham and Ralls 1998, Saccheri *et al.* 1998).

An area of particular concern is Santa Nella in western Merced County where pending development plans threaten to eliminate the little suitable habitat that remains and provides a dispersal corridor for kit foxes between the northern and southern portions of their range. Preliminary estimates of expected heterozygosity from foxes in this area indicate that this population may already have reduced genetic variation.

Other populations that may be showing the initial signs of genetic isolation are the Lost Hills area and populations in the Salinas-Pajaro River watershed (i.e., Camp Roberts and Fort Hunter Liggett). Preliminary estimates of the mean number of alleles per locus from foxes in these populations indicate that allelic diversity is lower than expected. Although these results may, in part, be due to the small number of foxes sampled in these areas, they may also be indicative of an increase in the amount of inbreeding due to population subdivision (M. Schwartz, University of Montana, Missoula, pers. comm. on March 23, 2000, to P. J. White, Fish and Wildlife Service, Sacramento, California). Further sampling and analyses are necessary to adequately assess the effects of these potential genetic bottlenecks.

Arid systems are characterized by unpredictable fluctuations in precipitation, which lead to high frequency, high amplitude fluctuations in the abundance of mammalian prey for kit foxes

(Goldingay *et al.* 1997, White and Garrott 1999). Because the reproductive and neonatal survival rates of kit foxes are strongly depressed at low prey densities (White and Ralls 1993; White and Garrott 1997, 1999), periods of prey scarcity owing to drought or excessive rain events can contribute to population crashes and marked instability in the abundance and distribution of kit foxes (White and Garrott 1999). In other words, unpredictable, short-term fluctuations in precipitation and, in turn, prey abundance can generate frequent, rapid decreases in kit fox density that increase the extinction risk for small, isolated populations.

The primary goal of the recovery strategy for kit foxes identified in the Recovery Plan is to establish a complex of interconnected core and satellite populations throughout the species' range. The long-term viability of each of these core and satellite populations depends partly upon periodic dispersal and genetic flow between them. Therefore, kit fox movement corridors between these populations must be preserved and maintained. In the northern range, from the Ciervo Panoche in Fresno County northward, kit fox populations are small and isolated, and have exhibited significant decline. The core populations are the Ciervo Panoche area, the Carrizo Plain area, and the western Kern County population. Satellite populations are found in the urban Bakersfield area, Porterville/Lake Success area, Creighton Ranch/Pixley Wildlife Refuge, Allensworth Ecological Reserve, Semitropic/Kern National Wildlife Refuge (NWR), Antelope Plain, eastern Kern grasslands, Pleasant Valley, western Madera County, Santa Nella, Kesterson NWR, and Contra Costa County. Major corridors connecting these population areas are on the east and west side of the San Joaquin Valley, around the bottom of the Valley, and cross-valley corridors in Kern, Fresno, and Merced counties.

In response to the drastic loss of habitat and steadily increasing fragmentation, California Department of Transportation and the Service convened a San Joaquin Kit Fox Conservation and Planning Team to address the rapid decline of kit fox habitat in the northern range, and increasing barriers to kit fox dispersal. Consisting of Federal, State, and local agencies, local land trusts, environmental groups, researchers, and other concerned individuals, the goal of this team was to coordinate agency actions that will recover the species, and troubleshoot threats to San Joaquin kit foxes as they emerge. Between the years 2001-2003, the team addressed connectivity issues at specific points along the west-side corridor north of the Ciervo Panoche core population.

Baseline

The historic range of the kit fox extended from southern Kern County north to Contra Costa County. In 1979, less than 7% of the estimated historic wild lands of the San Joaquin Valley remained undeveloped (USFWS 2006). The Service recognizes loss and degradation of habitat by agricultural, industrial, and urban developments and associated practices as factors that continue to decrease the carrying capacity of remaining habitat and threaten kit fox survival. Such losses contribute to kit fox declines through displacement, direct and indirect mortalities, barriers to movement, and reduction of prey populations (USFWS 2006). Since the 1970s, researchers have identified predation, starvation, flooding, and drought as natural mortality factors. Human-induced mortality factors include shooting, trapping, poisoning, electrocution, road kills, and suffocation (Brown et al 2006).

The primary goal of the recovery strategy for kit foxes identified in the *Recovery Plan for Upland Species of the San Joaquin Valley, California* (Service 1998) is to establish a complex of interconnected core and satellite populations throughout the species' range. The long-term viability of each of these core and satellite populations depends partly upon periodic dispersal and genetic flow between them. Therefore, kit fox movement corridors between these populations must be preserved and maintained. In the northern range, from the Ciervo Panoche in Fresno County northward, kit fox populations are small and isolated, and have exhibited significant decline. The core populations are the Ciervo Panoche area, the Carrizo Plain area, and the western Kern County population. Satellite populations are found in the urban Bakersfield area, Porterville/Lake Success area, Creighton Ranch/Pixley Wildlife Refuge, Allensworth Ecological Reserve, Semitropic/Kern National Wildlife Refuge (NWR), Antelope Plain, eastern Kern grasslands, Pleasant Valley, western Madera County, Santa Nella, Kesterson NWR, and Contra Costa County. Major corridors connecting these population areas are on the east and west side of the San Joaquin Valley including the Millerton Lake area of Fresno County, around the bottom of the Valley, and cross-valley corridors in Kern, Fresno, and Merced counties. The proposed project is located along the eastern boundary of the northern core population area, and there is contiguous non-irrigated agricultural habitat linked between the northern core population area and the proposed project. Kit fox may use the project area as a corridor for migration and foraging. The Service has identified the project area to be preserved for kit fox connectivity. The nearest CNDDB occurrence is approximately 3 miles west of the project site recorded in 1999.

Effects of the Proposed Action

This section includes the analysis of the direct, indirect, and cumulative effects of the project on the kit fox. The analysis identifies the project features and/or activities that are anticipated to adversely impact the species and when feasible, quantifies such impacts.

Proposed ground disturbance and physical habitat alteration resulting from construction activities for the proposed project will result in 9.0 acres of temporary impacts and 16.8 acres of permanent impacts to kit fox habitat, none of which are within Federally designated critical habitat. Nonetheless, the cumulative 25.8 acres of affected habitat exists within a substantial anthropogenic disturbance regime.

In the absence of any recent empirical data, kit foxes that are known to forage or may occur in the project vicinity are assumed to have acclimated and developed tolerance to substantial noise, light, and other affects resulting from the presence of an active pomegranate orchard, electrical facilities, vehicle traffic, noise, etc. An additional unquantifiable acreage of suitable foraging habitat will be affected by construction and operational noise, light, and other impacts discussed below. Adequate research has not been conducted specifically on the kit fox to quantify these affects. However, the PEC has committed to implement a number of avoidance and minimization measures and support the long-term preservation of the kit fox. This is being accomplished by contributing conservation funding to help secure the highest quality habitat that is in private ownership and on potentially developable parcels. The PEC's contributions will help ensure that needed habitat, wildlife linkages and connectivity are maintained; which benefit a robust suite of plant and wildlife species, including kit fox.

Potential effects from the proposed action to kit fox were based on the proposed project location, construction methods, and the resource protection measures adopted as part of the project. Additional considerations and sensitivities included:

- Construction-related impacts (e.g., construction, vegetation clearing and grading, increased traffic, lighting, noise, vibrations, etc.);
- Post-construction operational noise, light and vibration impacts from PEC use;
- Post-construction PEC maintenance activities (e.g., herbicides, road maintenance, etc.);
- Affects on habitat connectivity (e.g., upland and breeding connectivity, movement corridors, landscape linkages, etc.); and
- Direct loss/mortality (e.g., habitat loss and or modification).

In general, construction activities and post-construction maintenance and operations could directly kill the kit fox, crush potential burrows, and/or temporarily displace them from some foraging habitat areas. The incremental increases in noise, light, vibration, and human activities associated with the construction activities are also expected to have the potential to cause the kit fox to avoid an area until the disturbances are eliminated or the animals become accustomed to the disturbance. However, ascertainable studies have been conducted to assess or quantify impacts of noise, light or vibration on the kit fox.

Kit fox seem to be fairly tolerant of human presence, although Link (1995) noted that Colorado kit foxes seemed to spend longer periods in their dens during weekend peaks of noise and disturbance by off-road vehicles or other forms of recreating. Vehicles passing on roads did not cause kit foxes to alter their behavior unless people stopped to watch them. Link (1995) located one occupied whelping den within 4 meters of a busy road. As the increase in human population in the Grand Valley and surroundings brings increased highway and off-highway travel, the likelihood of vehicle-related kit fox mortalities will rise (Fitzgerald 1996).

Construction will result in a permanent loss of 16 acres of habitat. Some disturbance to normal reproductive patterns could occur during the spring of 2008 for kit fox that may breed in close relation to the study area and other areas proposed for disturbance. This loss of productivity would be for only one season and individuals would be expected to reoccupy adjacent habitats following completion of construction activities. Post-construction maintenance and operations could also temporarily displace kit fox from some habitat areas.

Cumulative Effects

Per section 7 of the Endangered Species Act, cumulative effects analyses are limited to future State and private actions that are reasonably certain to occur within the area not expected to get a Federal permit. For section 7 consultations, the cumulative impacts should not include future Federal actions (e.g., undertakings that require Federal authorization or Federal funding) since they are actions that themselves would be subject to the restraints of section 7 at some later date. Indicators of "reasonably certain" projects must show more than the possibility that the non-Federal project would occur. They must demonstrate with reasonable certainty that it would occur. Accordingly, only those State or private projects that satisfy all major land use requirements and that appear to be economically viable are considered. Cumulative effects involve only future non-Federal actions: past and present impacts of non-Federal actions are part of the environmental baseline. The following subsections identify and describe potential cumulative effects that could result from the project in combination with other reasonably foreseeable future non-Federal actions or natural events in or near the PEC project area.

Future Actions Considered but Eliminated

Although identified in scoping comments and/or previous project analysis, the following actions (below table) were determined not to be reasonably foreseeable future actions and consequently were not considered in the cumulative effects assessment.

Dismissed Potential Projects for Cumulative Effects

Project Description	Project Location	Project Applicant	Status/Timing
Plan Check Power Generation Facility	APN: 027-060-61 This is the parcel directly adjacent and to the northeast of the subject site	Unknown	Plan Check submitted in June of 2001. Project has not yet been finalized (i.e., is not complete)
New Shell building with a convenience store	APN: 027-190-25	Unknown	Permit finalized in October of 2003

CalPeak Power Panoche No. 2

This existing power plant, which has been in operation since 2001, is directly adjacent to the project. It is unclear what the proposed project entailed (submitted in June of 2001) and why County of Fresno records indicates this project's permits have not been finalized. Since this plant is currently in operation, it can be assumed that any permits submitted subsequently are for relatively minor work and probably do not meet the 30,000 square foot criteria for projects that could potentially cause cumulative impacts. Thus, this project can be dismissed from the cumulative impact analysis because no cumulative impacts would occur.

Convenience Store Building

From the project description provided by the County of Fresno, this seems to be an addition to an already existing convenience store. Detailed information on this specific project was unavailable. However, it is highly unlikely that this building permit was for a structure that was equal to or over 30,000 square feet. Thus, this project can be dismissed from the cumulative impact analysis because no cumulative impacts would occur.

Reasonably Foreseeable Future Actions

Potential reasonably foreseeable future non-Federal actions were identified using the scoping comments; personal communication with resource experts, land use plans; and current events reported in local and regional news. Reasonably foreseeable future non-Federal actions considered in this cumulative impact assessment include projects that 1) are greater than 30,000 square feet; 2) have submitted a defined project application for required approvals or permits; or 3) have been previously approved and may be implemented in the near future. Cumulative impacts analysis focuses on the potential overlap of construction and operation impacts among various projects meeting the criteria described above.

Projects that will potentially contribute to cumulative impacts are those located in the same general geographic area of influence of the PEC. For this cumulative assessment, the area of influence is defined as the area within a 5-mile radius of the power plant. Projects or proposed projects of potential regional significance are also considered in the cumulative analysis. The following table presents a list of potential projects considered in this cumulative impacts assessment.

Projects Considered for Cumulative Effects

Project Description	Project Location	Project Applicant	Status/Timing
Proposed Starwood Power Plant to be 120 MW and operational in 2009	South of West Panoche Road and adjacent to the existing CalPeak Power Plant	Unknown	This proposed facility will be constructed at the same time as the PEC

Starwood Power Project

The proposed Starwood Power Project is a 120 MW peaker plant to be operational by 2009. This proposed power project will be a combustion turbine plant. Limited information indicates operational dates are similar to the PEC. The cumulative impacts associated with the concurrent construction schedules would be insignificant due to the short duration and lack of other pending development in the area. The operation of the proposed Starwood Power Project will occur during operation of the PEC. The simultaneous operation of both power plants will not result in significant cumulative impacts on environmental resources in the area except for noise impacts due to the relatively remote locations of the two power facilities.

Conclusion

After reviewing the current status of the kit fox, the environmental baseline for the area covered by this biological opinion, the effects of the proposed project, and the cumulative effects, it is the Service's biological opinion that the PEC Project, as proposed, is not likely to jeopardize the continued existence of the kit fox. The proposed project is not located within designated or proposed critical habitat for any federally-listed species, and therefore, none would be adversely modified or destroyed.

INCIDENTAL TAKE STATEMENT

Section 9 of the Act and Federal regulations issued pursuant to section 4(d) of the Act, prohibit take of endangered and threatened species without a special exemption. Take is defined as harass, harm, pursue, hunt, shoot, wound, kill, trap, capture or collect, or attempt to engage in any such conduct. Harm is further defined by the Service to include significant habitat modification or degradation that actually kills or injures a listed species by significantly impairing essential behavioral patterns, including breeding, feeding, or sheltering. Harass is defined by the Service as an intentional or negligent act or omission which creates the likelihood of injury to wildlife by annoying it to such an extent as to significantly disrupt normal behavioral patterns which include, but are not limited to, breeding, feeding, or sheltering. Incidental take is defined as take that is incidental to, and not the purpose of, the carrying out of an otherwise lawful activity. Under the terms of section 7(b)(4) and section 7(o)(2) of the Act, such incidental taking is not considered to be a prohibited taking under the Act provided that such taking is in compliance with this Incidental Take Statement.

The measures described below are non-discretionary and must be implemented by the PEC, as appropriate, in order for the exemption from section 7(o)(2) of the Act to apply. The PEC has a continuing duty to regulate the activity that is covered by this incidental take statement. If the PEC fails to retain oversight to ensure compliance with these measures, the protective coverage of section 7(o)(2) of the Act may lapse. To monitor the impacts of incidental take, the PEC must report the progress of the action and its impact on the species to our agency as specified [50 CFR §402.14(I)(3)].

Amount or Extent of Take

The Service expects that incidental take of the kit fox will be difficult to detect or quantify because when this mammal is not foraging, mating, or conducting other surface activity, it inhabits dens or burrows, the animal may range over a large territory, it is primarily active at night, it is a highly intelligent animal that is often is extremely shy around humans, and the finding of an injured or dead individual is unlikely because of their relatively small body size. Take of this species also may be difficult to quantify due to seasonal fluctuations in their behaviors and consequential exposure to threats. Therefore, the Service is estimating that all of the kit foxes permanently or temporarily occupying 25 acres, for the period of (2) years, as described herein, will be subject to incidental take from the project. Upon implementation of the Reasonable and Prudent Measures, incidental take associated with the Panoche Energy Center in the form of harm and harassment of the kit fox caused by habitat loss and construction activities will become exempt from the prohibitions described under section 9 of the Act.

Disposition of Sick, Injured, or Dead Specimens

This office is to be notified within three working days if any kit fox are found dead or injured as a direct or indirect result of the implementation of this project. Notification must include the date, time, location, and any other pertinent information as described in the project description. Dead animals should be collected in an appropriate manner by a biologist approved by the Service. The office contact person is Susan Jones, who may be contacted at the letterhead address or at (916) 414-6600.

Effect of Take

In the accompanying biological opinion, we determined that this level of anticipated take is not likely to result in jeopardy to the kit fox.

Reasonable and Prudent Measures

The following reasonable and prudent measures are necessary and appropriate to minimize the effect of the Panoche Energy Center Project on the kit fox.

1. The applicant will ensure that PEC shall implement the project as described within this biological opinion.

2. The applicant shall ensure their compliance with this biological opinion.

These reasonable and prudent measures, which include the following implementing terms and conditions, are designed to minimize the impact of incidental take on a species that might result from the development of PEC. If, during the course of the action, the level of incidental take identified in this opinion is exceeded, such incidental take would represent new information requiring review of the reasonable and prudent measures provided. The PEC must provide an explanation of the causes of the taking and review with the Service the need for possible modification of the reasonable and prudent measures.

Terms and Conditions

In order to be exempt from the prohibitions of section 9 of the Act, PEC shall comply with the following terms and conditions, which implement the reasonable and prudent measures described above. These terms and conditions are nondiscretionary.

1. The following Terms and Conditions implement Reasonable and Prudent Measure one (1):

a. The applicant shall comply with all the conservation measures outlined in this Biological Opinion.

2. The following Terms and Conditions implement Reasonable and Prudent Measure two (2):

   a. The applicant shall comply with the Reporting Requirements of this biological opinion.

Reporting Requirements

A post-construction compliance report prepared by a Service-approved monitoring biologist(s) shall be forwarded to the Chief, Endangered Species Division, at the Sacramento Fish and Wildlife Office within 30 calendar days of the completion of construction activity. This report shall detail (i) dates that construction occurred; (ii) pertinent information concerning the success of the Project in meeting compensation and other conservation measures; (iii) an explanation of failure to meet such measures, if any; (iv) known project effects on federally listed species, if any; (v) occurrences of incidental take of federally listed species, if any; and (vi) other pertinent information.

PEC shall notify the Service via electronic mail and telephone within three (3) working days of the death or injury to a listed species that occurs due to project-related activities, or is observed at the project site. Notification must include the date, time, location of the incident or of the finding of a dead or injured animal, and photographs of the specific animal. In the case of an injured animal, the animal shall be cared for by a licensed veterinarian or other qualified person. In the case of a dead animal, the individual animal should be preserved, as appropriate, and held in a secure location until instructions are received from the Service regarding the disposition of the specimen or the Service takes custody of the specimen. The Service contacts are: Chief of the Endangered Species Division (Central Valley) at 916/414-6600, and Scott Heard, Resident Agent-in-Charge of the Service's Law Enforcement Division at 916/414-6660. The California Department of Fish and Game contact is Ron Schlorff at 916/654-4262.

Any contractor or employee who, during routine operations and maintenance activities inadvertently kills or injures a State-listed wildlife species shall immediately report the incident to her or his supervisor or representative. The supervisor or representative must contact the California Department of Fish and Game immediately in the case of a dead or injured State-listed wildlife species. The California Department of Fish and Game contact for immediate assistance is State Dispatch at 916/445-0045.

Proof of environmental training requirements shall be delivered within 10 business days of the start of construction to the Chief of the Endangered Species Division, Sacramento Fish and Wildlife Office, 2800 Cottage Way, Room W-2605, Sacramento, California, 95825-1846.

CONSERVATION RECOMMENDATIONS

1. All new sightings of kit foxes should be reported to the Service and the California Natural Diversity Database.

2. The Service has developed the following conservation recommendations based, in part, on The Recovery Plan for Upland Species of the San Joaquin Valley, California (U.S. Fish and Wildlife Service 1998).

    a. Locate, map, and protect existing populations of the San Joaquin kit fox (Recovery Plan Tasks 2.2.17 and 2.2.24).

    b. Protect and create additional habitat for the kit fox in key portions of its range (Recovery Plan Tasks 2.1.19 and 5.1.5).

3. In order for the Service to be kept informed of actions minimizing or avoiding adverse effects or benefiting listed species or their habitats, the Service requests notification of the implementation of any conservation recommendations.

REINITIATION—CLOSING STATEMENT

This concludes formal consultation on the proposed Panoche Power Project. As provided in 50 CFR §402.16, reinitiation of formal consultation is required where discretionary Federal agency involvement or control over the action has been maintained (or is authorized by law) and if: (1) the amount or extent of incidental take is exceeded; (2) new information reveals effects of the agency action that may affect listed species or critical habitat in a manner or to an extent not considered in this opinion; (3) the agency action is subsequently modified in a manner that causes an effect to the listed species or critical habitat that was not considered in this opinion; or, (4) a new species is listed or critical habitat designated that may be affected by the action. In instances where the amount or extent of incidental take is exceeded, any operations causing such take must cease, pending reinitiation.

If you have any questions regarding this biological opinion on the proposed Panoche Energy Center project in Fresno County, California, please contact Jason Hanni or Susan Jones the San Joaquin Valley Branch Chief, at (916) 414-6600.

Enclosure:
Selected Review Criteria for Section 7 Off-site Compensation (from April 11, 2006 Service draft guidance)

cc:
Gary Chandler, Panoche Energy Center, South Jordan, Utah
Margaret Fitzgerald, URS Corporation, Santa Ana, California

George Robin, US EPA, San Francisco, California
Heather Blair, Aspen Environmental Group, Sacramento, California

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Selected Review Criteria for Conservation Banks and Section 7 Off Site Compensation

Rev. April 11, 2006

This list is not a comprehensive list, but gives a substantial number of the basic considerations and requirements necessary to establish protection for properties designated as compensation for project impacts.

In many instances, 'Service-approval,' as stated below, may be replaced with 'Agency-approval,' where other government agencies are involved, such as in Conservation Banking (eg. USACE, CDFG, EPA).

Property Assurances and Conservation Easement

Title Report (Preliminary at proposal, and Final Title Insurance at recordation)

1. Who holds fee title to property? Should be Bank Owner/Project Applicant. If not, there may be liability and contracting issues.
2. Are there any liens or encumbrances (existing debts or easements) on the property?
    a. Review necessary supporting instruments to evaluate liens and encumbrances. Property owner should submit a "Property Assessment and Warranty" which discusses each and every exception listed on the Preliminary and Final Title Insurance Policies, evaluating any potential impacts to the conservation values that could result from the exceptions (see below).
3. Could any of these liens or encumbrances potentially interfere with either biological/habitat values or ownership? If existing easements can potentially interfere with the conservation values/habitat of the property, those portions of the land should be removed from the Conservation Easement (CE), and deducted from the total number of credits or acres attributed to the site.
4. A Subordination Agreement is necessary if there is any outstanding debt on the property. Review Subordination Agreement for adequacy – the lending bank or other lien holder must agree to fully subordinate to each lien or encumbrance.

Legal Description and Parcel Map

1. Ensure accuracy of map, location and acreage protected under CE.
2. Both the map and the legal description should explain the boundaries of the Bank and/or boundaries of each individual Bank phase or individual project compensation sites. Individual project compensation sites should *not* have "leftover" areas for later use.

Conservation Easement

1. Should use current USFWS CE template;
2. Who will hold the easement?
    a. Must have third-party oversight by a qualified non-profit or government agency. Qualifications include:
        i. Organized under IRC 501(c)(3),

        ii. Qualified under CA Civil Code § 815
        iii. Bylaws, Articles of Incorporation, and biographies of Board of Directors on file at, and approved by, USFWS
            1. Must meet requirements of USFWS, including 51% disinterested parties on the Board of Directors

3. If not using the USFWS template, applicant should specify objections they have to the template as provided, and may substantially delay processing as they will require Solicitor review. Alternate CE's must be approved by the USFWS prior to recording.
4. Other (non-template) CE's should include, at a minimum, language to:
    a. **USFWS *must* be third-party beneficiary** or add language throughout the document in all appropriate places that will assure USFWS the right to enforce, inspect, and approve any and all uses and/or changes under the CE prior to occurrence (including land use, biological management or ownership). The alternative of adding language is difficult because we are not signatories to the CE, so you should make sure it is done through the Solicitor's Office.
    b. Reserve all mineral, air and water rights under CE as necessary to maintain and operate the Bank in perpetuity [USFWS § 2(D)]
    c. Ensure all future development rights are forfeited.
    d. Ensure all prohibited uses contained in USFWS CE template are addressed.
    e. Link the CE, the Management Plan, and the Endowment Trust fund within the document (e.g. note that each exists to support the others, and where each of the documents can be located if a copy is required).
5. There are probably many more specific concerns – should compare the content of each of the sections of the current USFWS CE to see where discrepancies lie, and to insert necessary language, particularly, but not exclusively, per:
    a. Rights of Grantee
    b. Remedies
    c. Injunctive Relief
    d. Enforcement Discretion
    e. Costs and Liabilities
    f. Taxes
    g. Hold Harmless
    h. No Hazardous Materials Liability
    i. Assignment and Transfer
    j. Amendment
    k. Funding
    l. Warranty
    m. Additional Interests

Property Assessment and Warranty

1. A summary and full explanation of all exceptions remaining on the title must be included, with a statement that the owner/Grantor accepts responsibility for all lands being placed under this CE as available for the primary purposes of

the easement, as stated in the easement, and assures that these lands have a free and clear title and are available to be placed under the CE.

Environmental Site Assessment – Phase I

1. Check for clear report
2. If there are issues – a proposal to address the issues should be included; remediation may be necessary

Service Area

1. Service Area for a Conservation Bank is based upon biological criteria, and must be approved by USFWS.
2. Documents should then include a map designating the proposed/approved Service Area, and a text description of the same area.

Restoration or Development Plan

1. Full plans for any habitat construction *must* be USFWS-*approved*, and all permits in place, ***prior*** to the start of construction of the habitat

Management Plan

1. Must be reviewed and approved by the USFWS for each individual Bank, or individual mitigation project, for target species baseline, adequacy of management and monitoring, and reporting requirements and schedules in perpetuity, etc.
2. Management Plan should also describe funding mechanisms, schedule, and reporting for the long term funding of the property
3. Appendices should include biological surveys, wetland delineation and USACE verification letter, and any required permitting information
4. A copy of the final Management Plan must be either recorded with the CE, or the CE must state in its body that the current management plan can be obtained upon request from any signatory wildlife agency.

Economic Analysis

1. Must be based upon the *final, approved* management plan.
2. Must include provision to adjust for CPI annually.
3. Must be based on appropriate, attainable, long-term interest rate.
4. Must address/account for all of the required funds (as below).

Performance Security, Contingency Security and Endowment Fund

All funds must be held, managed, accessed, expended and released according to agency-approved methods and procedures. There are a variety of requirements for each fund. Following is a general overview:

1. All funds must be held by qualified, Service-approved, non-profit organization or government agency [see requirements under CE, §2(a), above]
2. A full description of the trust account and investment methods must be agency-approved. All funds must be held according to minimum standards for assuring

maximum success in earning potential, and with assurances for no loss of principal

3. Disbursements or releases from each of the funds must be for documented expenditures, as they occur
4. A full economic analysis must be included to demonstrate how each of the required funding amounts was determined. This analysis must be approved by the agencies as being full, complete and adequate
5. A schedule and plan (including target date and full amount on that date) for funding each of the accounts must be submitted for approval

Agreement Contract

This would include a "Conservation Bank Agreement," "Bank Enabling Instrument," or other consolidating agreement that ties all of the associated documents together. Some general, basic (certainly not all-inclusive) concerns to include are:

1. Conservation Easement must be approved by any agencies involved prior to recording, and a recorded copy must be submitted to the agencies prior to the compensation taking effect in any way.
2. For an individual site, each of the primary documents – the CE, management plan and endowment trust – must reference the other two documents to link them together to fully address the compensation.
3. If not a Conservation Bank, individual project compensation should be addressed fully (within or by each document) as individual projects.
4. Responsible party (property owner) must be identified (and a valid party to the contract) as responsible for all funding, management, monitoring, and reporting of Bank or Compensation Site, in perpetuity.
5. Transfer and Assignment of property should be according to §9.0 of USFWS Bank Agreement template, or approved by USFWS
6. Any agreement must include remedies for any disputes per §10.0 of the USFWS Conservation Bank Agreement.
7. Applications for individual compensation sites must not include any "leftover" pre-approved acreages for future projects. Any future projects must be addressed individually.

NEPA COMPLIANCE CHECKLIST

State: California

Grant/Project Name: Panoche Energy Center, LLC

This proposal_X_ is; __is not completely covered by categorical exclusion No(s). __C1____, 516 DM 6 Appendix 1.

(check (X) one) (Review proposed activities. An appropriate categorical exclusion must be identified before completing the remainder of the Checklist. If a categorical exclusion cannot be identified, or the proposal cannot meet the qualifying criteria in the categorical exclusion, an EA must be prepared.)

Exceptions:

Will This Proposal *(check (X) yes or no for each item below)*:

Yes	No	
__	_X_	1. Have significant adverse effects on public health or safety.
__	_X_	2. Have adverse effects on such unique geographic characteristics as historic or cultural resources, park, recreation or refuge lands, wilderness areas, wild or scenic rivers, sole or principal drinking water aquifers, prime farmlands, wetlands, floodplains, or ecologically significant or critical areas, including those listed on the Department's National Register of Natural Land marks.
__	_X_	3. Have highly controversial environmental effects.
__	_X_	4. Have highly uncertain and potentially significant environmental effects or involve unique or unknown environmental risks.
__	_X_	5. Establish a precedent for future action or represent a decision in principle about future actions with potentially significant environmental effects.
__	_X_	6. Be directly related to other actions with individually insignificant, but cumulatively significant environmental effects.
__	_X_	7. Have adverse effects on properties listed or eligible for listing on the National Register of Historic Places.
__	_X_	8. Have adverse effects on species listed or proposed to be listed on the List of Endangered or Threatened Species, or have adverse effects on designated Critical Habitat for these species.
__	_X_	9. Have material adverse effects on resources requiring compliance with Executive Order 119 88 (Floodplain Management), Executive Order 119 90 (Protection of Wetlands), or the Fish and Wildlife Coordination Act.
__	_X_	10. Threaten to violate a Federal, State, local or tribal law or requirement imposed for the protection of the environment.

(If any of the above exceptions receive a "Yes" check (X), an EA must be prepared.)

Concurrences/Approvals:
Project Leader: [signature] Date: 8/15/07

State Authority Concurrence: ________________ Date: __________
(with financial assistance signature authority, if applicable)

Within the spirit and intent of the Council of Environmental Quality's regulations for implementing the National Environmental Policy Act (NEPA) and other statutes, orders, and policies that protect fish and wildlife resources, I have established the following administrative record and have determined that the grant/agreement/amendment:

_X_ **is a categorical exclusion as provided by 516 DM 6, Appendix 1. No further NEPA documentation will therefore be made.**

__ **is not completely covered by the categorical exclusion as provided by 516 DM 6, Appendix 1. An EA must be prepared.**

__ **includes other attached information supporting the Checklist.**

Service signature approval:

RO or WO Environmental Coordinator: ________________ Date: __________

Staff Specialist, Division of Federal Aid: ________________ Date: __________
(or authorized Service representative with financial assistance signature authority)

OMB Control No. 1018-0110
03/31/2004

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SLIP SHEET - EXHIBIT #12

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT'S PRELIMINARY DETERMINATION OF COMPLIANCE
MAY 4, 2007
(REDWELL)

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SLIP SHEET - EXHIBIT #13

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT'S FINAL DETERMINATION OF COMPLIANCE JULY 13, 2007 (REDWELL)

DECLARATIONS

14

NOEL CASIL

Prepared Direct Testimony
Of
Noel Casil
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Noel Casil and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's traffic and transportation impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.11, Traffic and Transportation
      Appendix T, Traffic Counts

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

10-1-07
Date

Noel Casil
Noel Casil

15

LANNY FISK

Prepared Direct Testimony
Of
Lanny Fisk
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Lanny Fisk and I am employed by PaleoResource Consultants.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's paleontological resources impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.8, Paleontological Resources
   Appendix K, Paleontological Resources Technical Report

   Data Adequacy Response(s): PALEO-14

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

01 October 2007
Date

Lanny H. Fisk PhD
Lanny Fisk

16

BRIAN HATOFF

Prepared Direct Testimony
Of
Brian Hatoff
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Brian Hatoff and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's cultural resources impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.7, Cultural Resources
   Appendix J, Cultural Resources Technical Report

   Data Request Response(s): CR-28 through CR-33

   Data Request Response(s) Round 2: CR-62 through CR-68, RECON-1, 9, 10, 11 Appendix A

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

10/01/07
Date

Brian Hatoff

17

LINCOLN HULSE

Prepared Direct Testimony
Of
Lincoln Hulse
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Lincoln Hulse and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's biological resources impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.6, Biological Resources
      Appendix N, Biological Resources

   Data Adequacy Response(s): BIO-4

   Data Request Response(s): BIO-27

   Data Request Response(s) Round 2: BIO-61, RECON-7, RECON-8

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

October 1, 2007
Date

Lincoln Hulse

18

DAVID JENKINS

Prepared Direct Testimony
Of
David Jenkins

1. Q. Please state your name and place of employment
   A. My name is David Jenkins and I am employed by Panoche Energy Center, LLC.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's environmental impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s)
      1.0, Executive Summary
      2.0, Project Objectives
      4.0, Alternatives
      5.9, Land Use
      6.0, Financial Information
      Appendix U, Phase I Site Assessment

   Data Adequacy Response(s): AQ-2, AQ-3, LAND-8, LAND-10 through LAND-13

   Data Request Response(s): LAND-39, LAND-40, SOCIO-42, VISRES-58, VISRES-59

   Data Request Response(s) Round 2: TRANS-71, TRANS-72, RECON-12 through RECON-15

   Fresno County Site Plan Review, March 26, 2007

   County of Fresno General Plan Conformity Application, July 26, 2007

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

Oct 2, 2007
Date

[signature]
David Jenkins

MICHAEL KING

Prepared Direct Testimony
Of
Michael King
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Michael King and I am employed by Panoche Energy Center, LLC.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's project engineering.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s)
   - 3.0 Facility Description and Location
   - Appendix A, Heat and Mass Balances,
   - Appendix B, Water Balances,
   - Appendix C, Civil Engineering Design and Criteria,
   - Appendix D, Structural Engineering Design and Criteria,
   - Appendix E, Mechanical Engineering Design and Criteria,
   - Appendix F, Electrical Engineering Design and Criteria,
   - Appendix G, Control Systems Engineering Design and Criteria,
   - Appendix H, Chemical Engineering Design and Criteria,
   - Appendix S, Storm Water Calculations

   Data Adequacy Response(s): PROJ-16, 17, 18, 20 through 26

   Data Request Response(s): TSE-51, VISRES-54, VISRES-56

   Data Request Response(s) Round 2: NOISE-69, NOISE-70
   RECON-2 through RECON-6

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

9-28-2007

Date

Michael King

20

JOHN LAGUE

Prepared Direct Testimony
Of
John Lague
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is John Lague and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's air quality and public health impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.2, Air Quality
   5.16, Public Health and Safety
   Appendix I, Air Quality Data
   Appendix O, Public Health

   Data Adequacy Response(s): AQ-1

   Data Request Response(s): AQ-1 through AQ-26, VISRES-52, 53, 55, 57

   Data Request Response(s) Round 2: Air Quality Supplement AQ4&22, AQ-9, AQ-10, AQ-23, AQ-26

   Other Documents:
   Revised Data Request Response AQ-26, January 24, 2007

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

Sept 28, 2007
Date

John Lague

Angela Leiba

Prepared Direct Testimony
Of
Angela Leiba
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Angela Leiba and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's visual resources impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.13, Visual Resources

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

10/1/07
Date

Angela Leiba

SLIP SHEET - EXHIBIT #22

THIS EXHIBIT HAS BEEN REMOVED

STUART ST. CLAIR

Prepared Direct Testimony
Of
Stuart St. Clair
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Stuart St. Clair and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's waste management impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. Data Request Response(s): WASTE-60,
   Appendix C, Limited Soil Investigation

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

September 28, 2007
Date

Stuart St. Clair
Stuart St. Clair

ERIC VONBERG

Prepared Direct Testimony
Of
Eric VonBerg
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Eric VonBerg and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's agriculture and soils and cumulative impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.4, Agriculture and Soils
   5.18, Cumulative Impacts

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

September 28, 2007
Date

Eric VonBerg

TRICIA WINTERBAUER

Prepared Direct Testimony
Of
Tricia Winterbauer
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Tricia Winterbauer and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's waste management, hazardous materials handling, and worker safety impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.14, Waste Management
   5.15, Hazardous Materials Handling
   5.17, Worker Safety

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

10/1/2007
Date

Tricia Winterbauer
Tricia Winterbauer

JENNIFER WU

Prepared Direct Testimony
Of
Jennifer Wu
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Jennifer Wu and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's socioeconomic impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.10, Socioeconomics

   Data Adequacy Response(s): PROJ-15, PROJ-19

   Data Request Response(s): SOCIO-43, SOCIO-44

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

28.Sept.07
Date

Jennifer Wu

TECHNICAL MEMORANDUM
PANOCHE ENERGY CENTER

EXPANDED EVALUATION OF WATER SUPPLY AND WASTEWATER DISCHARGE ALTERNATIVES

Submitted to

The California Energy Commission

March 2, 2007

Submitted by

Panoche Energy Center, LLC

With support from

URS

URS Corporation
2020 East First Street, Suite 400
Santa Ana, CA 92705
(714) 835-6886 Fax: (714) 433-7701

URS

March 2, 2007

James W. Reede, Jr., Ed.D.
Energy Facility Siting Project Manager
California Energy Commission
1516 - 9th Street
Sacramento, CA 95814

RE: Panoche Energy Center – Technical Memorandum on Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives

Dear Dr. Reede:

On behalf of Panoche Energy Center, LLC (PEC), URS Corporation respectfully submits the attached Technical Memorandum entitled "Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives." This document represents PEC's formal response to the water and wastewater data requests that were verbally expressed by you and Staff during the January 31, 2007 Data Response/Issue Resolution Workshop in Mendota, CA.

PEC appreciates this opportunity to provide the CEC with a summary of additional analysis of the water supply and wastewater disposal alternatives originally presented in its August 2, 2006 AFC submittal. PEC believes this additional analysis further substantiates its representation in the AFC that use of the Lower Aquifer for power plant water supply and use of Underground Injection Wells for wastewater disposal offer the best solution for water and wastewater management when considering environmental and economic impacts in the context of applicable LORS.

Given the critical nature of water and wastewater relative to both the CEC AFC process and the overall success of the PEC project, I ask that you and Staff review this Technical Memorandum prior to our meeting on March 7, 2007. As a result, the PEC team hopes that Staff's concerns as expressed at the Data Request/Issues Resolution Workshop will have been answered. I appreciate your consideration of this Technical Memorandum, and look forward to our discussions in its regard.

Sincerely,

Margaret M. Fitzgerald
Program Manager

Attachment
Cc: Eileen Allen, CEC
Roger Johnson, CEC
Dick Ratliff, CEC
Gary Chandler, PEC
Mike King, PEC
Dave Jenkins, PEC
Allan Thompson, PEC Counsel

URS Corporation
2020 East First Street, Suite 400
Santa Ana, California 92705
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Technical Memorandum
Panoche Energy Center

Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives –*March 2, 2007*

1.0 Background and Purpose

This Technical Memorandum follows and responds to discussions between California Energy Commission (CEC) staff and the Panoche Energy Center (PEC) at the January 31, 2007 Data Response and Issues Resolution Workshop. Specifically, CEC staff requested additional evaluation of the water supply and wastewater disposal alternatives and additional evidence to support PEC's Application for Certification (AFC) determination that use of the lower aquifer water for power plant cooling and emissions control is the best option. Further, CEC staff expressed concern about the timing of the U.S. Environmental Protection Agency's (EPA's) issuance of the Class I Non-hazardous Underground Injection Well (UIC) Permit relative to the CEC schedule, and the lack of evidence showing that the PEC's UIC design will work. Consequently, the PEC was asked to conduct further evaluation of the supply water and wastewater disposal alternatives and present "substantial evidence" that the selections presented in the AFC indeed are the most feasible environmental and economic options available.

This Technical Memorandum summarizes the PEC's additional study and analysis of the water and wastewater alternatives that consider environmental and economic impacts in the context of Laws, Ordinances, Regulations, and Standards. In doing so, the PEC believes that the original water management plans as detailed in the August 2, 2006 AFC are further validated. This memorandum provides a detailed description of the various water supply and wastewater disposal options and includes a thorough evaluation of the regulatory, technical, and economic feasibility of these options.

2.0 Project Description and Objectives

The PEC project is defined as a peaking and/or "load shaping" plant. The purpose of such a project is to provide electric power on very short notice to meet unexpected high demands from consumers. Pacific Gas & Electric (PG&E) issued a long-term Request for Offer (RFO) for Power Purchase on March 18, 2005. The RFO specifically states that "PG&E is seeking peaking and/or shaping products." The PEC was conceived as a result of this RFO. The load shaping products, such as the proposed PEC, provide PG&E with the ability to dispatch the plant whenever it deems necessary to meet fluctuating retail load. It should be noted that PG&E pays for only the capacity of the plant, at a prenegotiated rate, but the PEC is obligated to deliver guaranteed electrical output when PG&E dispatches the units. Load shaping products typically have low annual capacity factors as they are only on-line at times of high electricity demand. The absence of such peaking and load shaping resources can potentially result in rolling black-outs for residential, commercial, and industrial consumers.

The PEC has been designed to assure that the plant will deliver the guaranteed output to PG&E in accordance with the requirements of the contract between PEC and PG&E. The PEC is required to meet certain minimum conditions, which require:

1. A continuous, reliable and good quality water resource for plant cooling and other process applications; and
2. A reliable and environmentally sound wastewater disposal method.

It is important to note that during the evaluation phase of the project, the PEC considered the use of dry cooling to minimize water use since water supply of good quality is not abundantly available at the site. However, considering the location and the weather conditions at the site, this option was ruled out as being not practical since the ambient temperatures during summer when power is in high demand can reach up to 114 degrees Fahrenheit (°F). The plant's output would fall precipitously at those ambient temperatures if dry cooling was utilized. In other words, during peak conditions when the PEC is contractually required to deliver certain megawatts (MW) of power to the grid, the PEC would not be able to provide sufficient cooling to the plant to in order to produce the required amount of electricity. The reasons for the shortfall in electricity generation under an air cooled scenario are described in more detail below.

The PEC proposes to install a high-efficiency combustion turbine for power generation. GE's LMS100 is a unique technology designed to utilize an intercooler for the inlet air as it is compressed, allowing for approximately 10% greater thermal efficiency than existing commercial simple cycle peaking units. This design also requires an efficient methodology to reject the intercooled air heat under peak ambient conditions consisting of air temperatures of 114 °F.

The PEC conducted an evaluation of a "dry cooling" design versus the proposed plant design of water cooling. Power output at 114 °F is 81 MW lower (i.e., 20% less) for a dry cooled plant than with a cooling tower and evaporative coolers. For a plant design with dry cooling, the PEC would have to install a fifth LMS100 turbine at an estimated cost of $70M to meet the power generation shortfall and satisfy the contractual requirements with PG&E.

In summary, after comparing dry cooling and water cooled systems, the following conclusions were reached:

1. A dry cooled system would require an additional turbine to be installed for the same power output under peak conditions; and
2. For a dry cooled system, the increase in fuel burned per MW produced would also result in increased air pollutant emissions by up to 20% under peak conditions.

Due to the estimated $70M additional cost for installation of a fifth turbine for the same output , the use of dry cooling is economically unsound for this project.

3.0 Project Water Supply

3.1 Project Water Supply – Guiding Principles

The state of California has adopted policies regarding the use of inland waters for power plant cooling. These policies require that fresh water be conserved and used for power plant cooling only if other water sources are environmentally undesirable or economically unsound. The 2003 Integrated Energy Policy Report (page 40) stated that the CEC has responsibility "to apply state water policy to minimize the use of fresh water, promote alternate cooling technologies and minimize or avoid degradation of the quality of the state's water resources." In the CEC Final Decision in the Consumnes Power Plant Project (01-AFC-19), the Commission summarized the requirements of California Water Code section 13550 et seq. and California State Water Resources Board Resolution 75-58, "...the use of potable or fresh inland water for power plant cooling as an unreasonable use and only to be used if other sources or other methods of cooling would be environmentally undesirable or economically unsound" (Page 206). This guidance leads to the following three areas of discussion of the Applicant's water supply: 1) Is the water source "fresh," 2) Does the water supply comply with the "cascading" requirements of Resolution 75-58, and 3) Will the project minimize the degradation of the state's waters. Finally, if the project would cause a significant impact upon the environment, a range of alternatives must be considered.

The cascading requirements of the Resolution 75-58 are as follows:

- Wastewater being discharged to the ocean;
- Ocean water;
- Brackish water from natural sources or irrigation return flow;
- Inland wastewaters of low total dissolved solids (TDS); and
- Other inland waters.

3.2 Project Water Supply - Alternatives

3.2.1 Surface Water

As stated in the AFC, sources of surface water large enough to meet the PEC's needs are not located in sufficient proximity to the site for consideration as a source of water supply.

3.2.1.1 Ocean Water

Due to the distance of the PEC from the Pacific Ocean, as well as the high concentrations of TDS, this alternative was dropped from further consideration. (See "Surface Water" above.)

3.2.1.2 SWP Water

The California Aqueduct, a joint use Storm Water Project /Central Valley Project (SWP/CVP) facility (the CVP share is known as the San Luis Canal), is located three miles east of the PEC site. This aqueduct receives flows from the Sacramento-San Joaquin River Delta and the San Luis Reservoir. Water available from the SWP is of superior quality, with TDS levels averaging about 250 to 300 milligrams per liter (mg/L). This compares to 860 to 1,100 mg/L in the confined aquifer and greater than 2,900 mg/L in the semi-confined aquifer beneath the PEC site. However, the PEC site lies outside the State Water Resources Control Board Designated Permitted Place of Use for SWP water. Therefore, SWP water cannot legally be delivered to the PEC site. Further, as stated in the AFC, the Applicant determined that use of potable water from the California Aqueduct is inconsistent with the priority of use of water supplies for power plant cooling identified in the State Water Policy, since lower quality water is available at the PEC (i.e., lower aquifer water). Consistent with the PEC AFC, this SWP alternative was eliminated from further consideration. No further information is available to change this conclusion.

3.2.1.4 Federal CVP Water

Federal CVP water in the PEC area is conveyed via two facilities. First is the Delta-Mendota Canal a CVP-owned facility, the terminus of which is located 1 mile north of the City of Mendota, about 18 miles from the PEC. Second, as noted above, CVP water is also conveyed in the San Luis Canal, the federal share of the joint use facility also known as the SWP California Aqueduct. As stated in the AFC, in 2002, Westlands Water District Board of Directors made a determination that no new nonagricultural service connections would be served if annual water use was going to be more than 5 acre-feet. According to available information, Westlands has not changed its position in this matter. Further, as stated in the AFC, the Applicant determined that use of potable water from the SWP California Aqueduct/CVP San Luis Canal is inconsistent with the priority of use of water supplies for power plant cooling identified in the State Water Policy, as brackish water is available at the PEC. This alternative was eliminated from further consideration. No further information is available to change this conclusion.

3.2.1.5 Reclaimed Water

Reclaimed water (i.e., wastewater receiving tertiary treatment) is not available in the vicinity of the PEC. The wastewater treatment plants (i.e., Publicly Owned Treatment Works [POTW]) closest to the PEC are:

1. The City of Mendota, located approximately16 miles from the site, has a wastewater treatment capacity of approximately 1.2 million gallons per day (MGD) (based on a monthly average). The Mendota POTW does not have capacity to generate reclaimed water at this stage.
2. The City of Firebaugh, located approximately 25 miles from the site, has a wastewater treatment capacity of 1.5 MGD, and only provides secondary treatment. It produces limited amounts of water for recycling that is mostly used locally by farmers for non-food irrigation. Currently, it has no reclaimed water capacity to spare for additional usage, such as for the PEC project.

In summary, reclaimed water use is not feasible because of the distance to the reclaimed water sources and their lack of capacity.

3.2.2 Agricultural Water (Irrigation Return Flows)

There are two general categories of irrigation return flows in the general vicinity of the PEC. These categories, subsurface drainage and surface return flows, are discussed as follows.

<u>Subsurface Drainage</u>

Wastewaters from subsurface agricultural drains in the project area, the closest active systems being about 10 miles away, generally exhibit high levels of selenium, magnesium, and other dissolved solids that are considered toxic to fish and other wildlife. Previous evaluations have determined that treatment of these wastewaters to make them suitable for disposal would cost approximately \$3,000 to \$4,000 per acre-foot. No estimates are available for additional treatment sufficient to allow reuse. Further, the Westlands Water District's experience with water that was conveyed by the San Luis Drain has shown significant encrustation and has highly corrosive and abrasive qualities that damaged pumps and related equipment beyond simple repair/maintenance after only a few thousand hours of operation.

The San Luis Drain is 14 miles from the PEC site and is 265 feet lower in elevation. As reported by the Fresno Bee, February 2007, all discharges of shallow groundwater to the San Luis Drain were terminated in August 1986 under court order and state regulatory actions. To meet this court order, Westlands Water District removed all shallow groundwater drainage pumps and installed about 100 semi-permanent plugs in the drainage collector system pipelines. In addition, many growers who formerly had drainage service installed plugs in their farm drainage collection systems. Therefore, there is no longer any shallow groundwater in the San Luis Drain within the Westlands Water District.

In addition, all lands previously discharging shallow groundwater to the San Luis Drain and other surrounding areas are subject to a litigation settlement land retirement program. The United States Bureau of Reclamation and Westlands Water District have already retired approximately 125,000 acres from agricultural production in the project area and are currently considering a proposal that would lead to the retirement of up to an additional 275,000 acres in this general area due to the absence of feasible alternatives to treat and manage these wastewaters. Once retired, and lacking irrigation, there is no longer shallow groundwater emanating from these lands. Therefore, even if the subsurface water could be treated, the pipeline plugs removed, the drainage pumps reinstalled, and farm drainage systems restored and court orders and regulatory actions overcome, there would be no water entering the San Luis Drain absent the now retired land being returned to production, which could be in violation of the litigation settlement to keep the lands out of irrigated agricultural production. This water supply alternative was eliminated from further consideration. No further information is available to change this conclusion.

Surface Return Flows

The second category of irrigation return flows is surface runoff from furrow, flood, or other irrigation practices. Due to the high cost of water in the project area, tailwater collection and reuse systems are extensively employed to collect, convey, store, and recycle surface runoff from irrigation practices. However, due to the high cost of water supply, most land in agricultural production in the project area uses aboveground or buried drip, microsprinkler or sprinkler irrigation methods that normally do not generate surface runoff. The extent to which any runoff is produced, the water is normally recycled in the irrigation process. If this water was used for any other purpose, such as PEC cooling water, it would have to be replaced with an equal quantity of surface water. As noted above, much of the agricultural lands that previously discharged irrigation tailwater have been retired from production due to concerns regarding selenium contamination of the underlying shallow groundwater.

Use of Agricultural water recovery was investigated in October, 2005 for the PEC project. Baker Farming, the agricultural operation site adjacent to the PEC, utilizes a drip irrigation and micro sprinkler irrigation systems which do not typically produce any "runoff." However, each quarter section of land contains a filtration system that must be backwashed periodically. Baker Farming, like other farms in the PEC area, has developed a system to recover this backwash water and reuse it for irrigation. The PEC held discussions with Baker Farming about the potential of using this water for the project. Baker Farming recovers backwash water at a volume equivalent to about one-third of the water supply needs of the PEC, but not necessarily at the times required. This alternative is therefore not feasible because the water supply would be inadequate. However, this potential source of water supply was dropped from consideration when it also became evident that Baker Farming would be required to replace (offset) water supplied to the project with additional water from fresh water sources, thus defeating the purpose of not using fresh water sources for power plant cooling.

Use of surface runoff was eliminated as a water supply alternative because it was determined to be not feasible and environmentally undesirable.

3.2.3 Groundwater

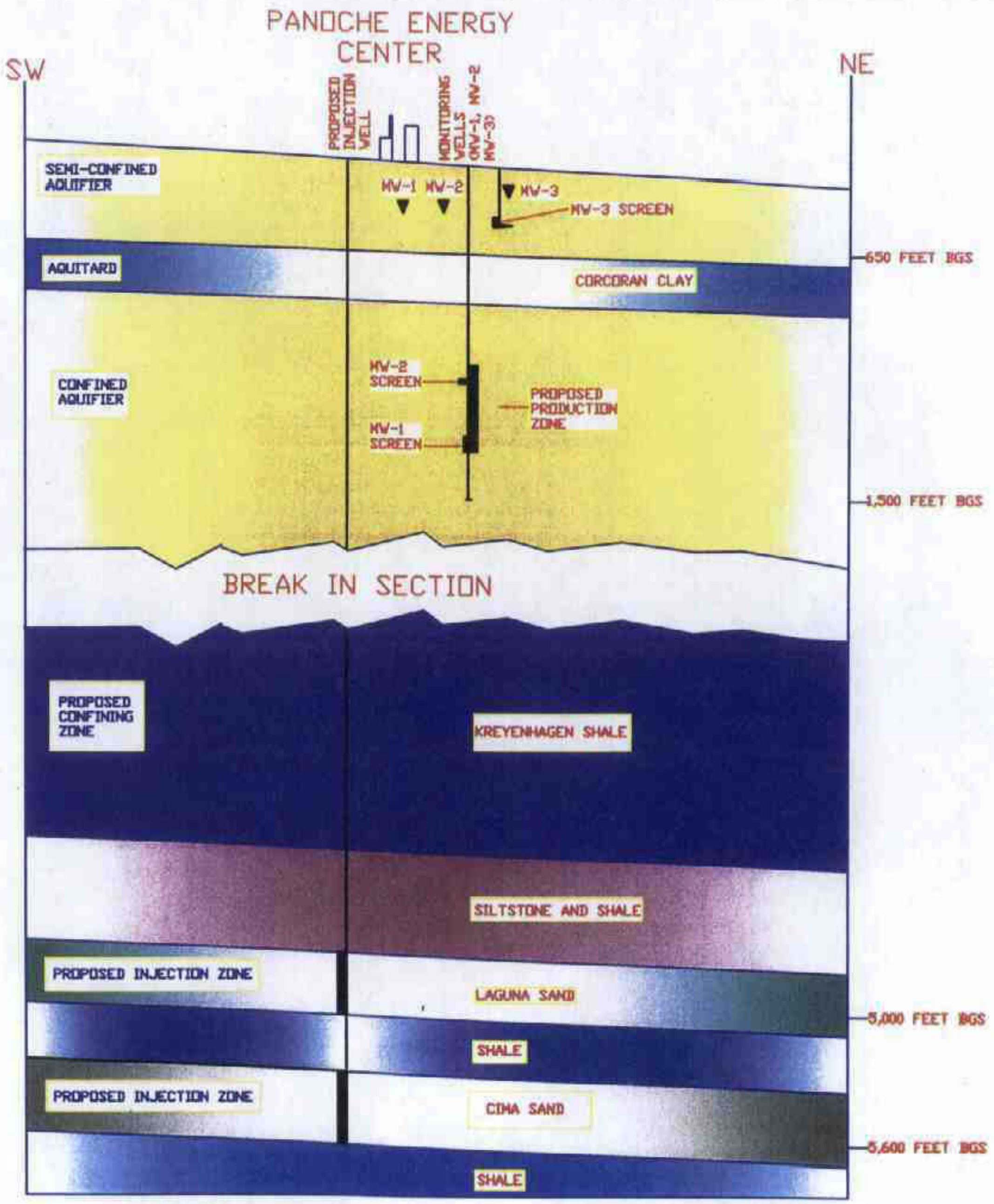
The aquifer system comprising the Westside Subbasin consists of unconsolidated continental deposits of Tertiary and Quaternary age. These deposits form an unconfined to semi-confined aquifer overlying a confined aquifer, as shown on Figure 3.1. These aquifers are separated by an aquitard that is composed of the Corcoran Clay member of the Tulare Formation.

Suitability of groundwater as a project water supply alternative for the PEC has been evaluated on the basis of groundwater quality and availability within the two aquifers underlying the site. Groundwater quality has been evaluated using data from two sets of groundwater samples collected from monitoring wells installed at the PEC site, reported data from an adjacent site, and published data for the surrounding area. Groundwater availability was evaluated using the performance of agricultural irrigation wells formerly common in the area and the groundwater model prepared for the PEC site, as described below.

As part of the production water assessment, a groundwater flow model was compiled to simulate groundwater underlying the PEC site and surrounding area. The groundwater flow model was developed using the Brigham Young University Environmental Modeling Research Laboratory (EMRL) Groundwater Modeling System (GMS), Version 6.0 (EMRL, 2006). GMS is a comprehensive graphical user interface (GUI) for performing groundwater simulations that utilize several groundwater modeling codes, including MODFLOW and MODPATH. The GMS was used to develop a site conceptual hydrogeological model and to convert it into a 3-D groundwater flow model. Several reasonable and practical assumptions, based on field conditions and professional judgments, are required for the model. The model is divided into three layers that represent the semi-confined aquifer (layer 1), the Corcoran Clay (layer 2), and the confined aquifer (layer 3). Model layers 1 and 2 are simulated as unconfined aquifers, and model layer 3 is simulated as a confined aquifer. The starting heads for the model were calculated from a recent groundwater investigation performed for PEC site (URS, 2006) and local groundwater elevation maps (Westlands Water District, 2001). Additional data used to construct the groundwater model were obtained from the Groundwater Flow in the Central Valley Report (Williamson et. al., 1989). This model was introduced in the response to CEC Data Request 47 and has been modified based on recently acquired hydraulic conductivity estimates described in Section 3.2.7.2.

3.2.3.1 Semi-Confined Aquifer Water Quality

Groundwater samples collected from an on-site monitoring well (i.e., MW-3) screened from 440 to 460 feet below ground surface (bgs) indicate that groundwater quality within the semi-confined aquifer underlying the site is impacted by relatively high concentrations of several constituents including TDS, sulfate, hardness, and silica (Tables 3.1 and 3.2). Multiple constituents exceed published water quality limits, including California Department of Health Services (CDHS) and EPA's Primary and Secondary Maximum Contaminant Limits (MCLs) and agricultural water quality limits (Regional Water Quality Control Board [RWQCB], 2003).



EXPLANATION:

MW-3 ▼ GROUNDWATER SURFACE MEASURED IN MONITORING WELL INDICATED

SCREENED INTERVAL OF EXISTING OR PROPOSED WELL

URS Corporation

CONCEPTUAL CROSS SECTION
PEC PROJECT WATER SUPPLY
& WASTEWATER DISPOSAL

Proj. No.: 29869662	DATE: 3/1/07	
	Figure: 3.1	Rev.
	Scale: NOT TO SCALE	

TABLE 3.1
INORGANICS CONCENTRATIONS IN WATER
Panoche Energy Center
Fresno County, California

Well Identification		Lower Confined Aquifer MW-1			Upper Confined Aquifer MW-2			Semi-Confined Aquifer		Water Quality Limits For Constituents[a]					
										CDHS[b]		USEPA[c]			
Sample Identification		MW-1	MW-4 (Blind Duplicate of MW-1)	MW-1	MW-2	MW-5 (Blind Duplicate of MW-2)	MW-2	MW-3		Primary MCL[d]	Secondary MCL[e]	Primary MCL	Secondary MCL	CA PHG[f]	Ag Water Quality Limits[g]
		Sample Date													
Constituent or Parameter	Units	10/25/2006	10/25/2006	2/16/2007	10/25/2006	10/25/2006	2/16/2007	10/27/2006	2/16/2007						
Total Alkalinity as $CaCO_3$	mg/L[h]	180	180	180	110	110	100	180	170	-	-	-	-	-	-
Bicarbonate Alkalinity as HCO_3	mg/L	200	200	200	130	140	120	230	210	-	-	-	-	-	-
Carbonate Alkalinity as CO_3	mg/L	< 20	< 20	<20	< 20	< 20	<20	< 20	<20						
Hydroxide Alkalinity as OH	mg/L	< 20	< 20	<20	< 20	< 20	<20	< 20	<20						
Ammonia as N	mg/L	< 1.0	< 1.0	<1.0	< 1.0	< 1.0	<1.0	< 1.0	<1.0						
Biochemical Oxygen Demand	mg/L	< 1.0	< 1.0	1.5	< 1.0	< 1.0	<1.0	< 1.0	<1.0						
Chloride	mg/L	85	85	73	40	41	42	**160**	**160**	-	250	-	250	-	106
Chemical Oxygen Demand	mg/L	< 10	< 10	24	26	< 10	16	< 10	11	-	-	-	-	-	-
Cyanide (total)	mg/L	< 0.005	< 0.005	<0.0050	< 0.005	< 0.005	<0.0050	< 0.005	<0.0050						
Specific Conductance (EC)	µS/cm[i]	**1,500**	**1,500**	**1,500**	**1,100**	**1,100**	**1,200**	**3,000**	**3,200**		900			-	700
Fluoride	mg/L	0.60	0.68	0.44	0.56	0.59	0.35	0.71	0.50	2		4	2	1	1
Hardness	mg equiv. $CaCO_3$/L[j]	40	41	48	56	56	42	1,100	1,200	-	-	-	-	-	-
Methylene Blue Active Substances	mg/L	< 0.050	< 0.050	<0.050	< 0.050	< 0.050	<0.050	< 0.050	<0.050						
Nitrate as NO_3	mg/L	< 6.0	< 6.0	<2.0	< 6.0	< 6.0	<2.0	**27**	**31**	45	-	10	-	10	-
Orthophosphate as P	mg/L	< 1.5	< 1.5	<0.50	< 1.5	< 1.5	<0.50	< 1.5	<0.50						
pH	pH units	**8.9**	**9.0**	**8.7**	**8.6**	**8.6**	**8.5**	8.1	8.0				6.5 - 8.5		6.5 - 8.4
Phosphorus	mg/L	0.12	0.16	0.15	0.14	< 0.10	0.11	< 0.10	<0.10	-	-	-	-	-	-
Sulfate as SO_4	mg/L	**440**	**440**	**410**	**380**	**400**	**370**	**1,500**	**1,500**	-	250	500	250	-	-
Sulfide	mg/L	< 1.0[k]	< 1.0[k]	--	< 1.0[k]	< 1.0[k]	--	< 1.0	--						
Total Dissolved Solids	mg/L	**1,100**	**1,100**	**1,000**	**840**	**840**	**850**	**2,900**	**2,900**	-	500	-	500	-	450
Total Organic Carbon	mg/L	1	< 1.0	1.0	< 1.0	1	<1.0	< 1.0	<1.0	-	-	-	-	-	-
Total Suspended Solids	mg/L	110	94	76	25	15	<40	< 4.0	<10	-	-	-	-	-	-
Turbidity	NTU[l]	**89[m]**	**87[m]**	**200**	**52[m]**	**45[m]**	**180**	**2.3**	**19**	1 or 5	5	1 or 5	-	-	-

Note: Values shown in bold print exceed one or more water quality limits shown on right.
[a] Water quality limits for detected constituents summarized from A Compilation of Water Quality Goals, August, 2003, Regional Water Quality Control Board, Central Valley Region
[b] California Department of Health Services
[c] U.S. Environmental Protection Agency
[d] Primary Maximum Contaminant Level
[e] Secondary Maximum Contaminant Level
[f] California Office of Environmental Health Hazard Assessment Public Health Goal in Drinking Water
[g] Agricultural Water Quality Limits based on Ayers, R.S. and D.W. Westcot, Water Quality for Agriculture, Food and Agriculture Organization of the United Nations - Irrigation and Drainage Paper No. 29, Rev. 1, Rome, 1965, as summarized in A Compilation of Water Quality Goals, August, 2003
[h] mg/L = milligrams per liter
[i] µS/cm = microsiemens per centimeter
[j] mg equiv. $CaCO_3$/L = milligrams equivlent calcium carbonate
[k] Analyst noted that samples were orange in color and indicated possible matrix interference
[l] NTU = Nephelometric Turbidity Units
[m] Sample analyzed outside of U.S. Environmental Protection Agency recommended holding time

TABLE 3.2
METALS CONCENTRATIONS IN WATER
Panoche Energy Center
Fresno County, California

Well Identification		Lower Confined Aquifer			Upper Confined Aquifer			Semi-Confined Aquifer		Water Quality Limits For Constituents[a]					
		MW-1			MW-2			MW-3		CDHS[b]		USEPA[c]			
Sample Identification		MW-1	MW-4 (Blind Duplicate of MW-1)	MW-1	MW-2	MW-5 (Blind Duplicate of MW-2)	MW-2			Primary MCL[d]	Secondary MCL[e]	Primary MCL	Secondary MCL	CA PHG[f]	Ag Water Quality Limits[g]
		Sample Date													
Constituent	Units	10/25/2006	10/25/2006	2/16/2007	10/25/2006	10/25/2006	2/16/2007	10/27/2006	2/16/2007						
Aluminum	mg/L[h]	< 0.050	< 0.050	0.61	< 0.050	< 0.050	<0.050	< 0.050	<0.050						
Antimony	mg/L	< 0.0050	< 0.0050	<0.0050	< 0.0050	< 0.0050	<0.0050	< 0.0050	<0.0050						
Arsenic	mg/L	< 0.010	< 0.010	0.016	< 0.010	< 0.010	<0.010	< 0.010	<0.010						
Barium	mg/L	0.19	0.18	0.046	0.16	0.16	0.017	0.14	0.013	1		2		0.7	
Beryllium	mg/L	< 0.0010	< 0.0010	<0.0010	< 0.0010	< 0.0010	<0.0010	< 0.0010	<0.0010						
Boron	mg/L	**2.9**	**3.0**	**2.9**	**1.6**	**1.7**	**1.7**	**4.1**	**4.2**	-	-	-	-	-	0.7 or 0.75
Cadmium	mg/L	< 0.0010	< 0.0010	<0.0010	< 0.0010	< 0.0010	<0.0010	< 0.0010	<0.0010						
Calcium	mg/L	11	11	13	20	20	15	170	180	-	-	-	-	-	-
Chromium	mg/L	< 0.0050	< 0.0050	<0.0050	< 0.0050	< 0.0050	<0.0050	< 0.0050	0.020						
Cobalt	mg/L	< 0.0020	< 0.0020	<0.0020	< 0.0020	< 0.0020	<0.0020	< 0.0020	<0.0020						
Copper	mg/L	< 0.0050	< 0.0050	<0.0050	< 0.0050	< 0.0050	<0.0050	< 0.0050	<0.0050						
Iron	mg/L	**5.9**	**5.8**	**45**	**3.9**	**3.3**	**42**	< 0.10	**5.3**	-	0.3	-	0.3	-	5
Lead	mg/L	< 0.0050	< 0.0050	<0.0050	< 0.0050	< 0.0050	<0.0050	< 0.0050	<0.0050						
Magnesium	mg/L	3.1	3.2	3.7	1.4	1.5	1.1	170	180	-	-	-	-	-	-
Manganese	mg/L	**0.12**	**0.12**	**0.36**	**0.08**	**0.076**	**0.29**	**0.064**	**0.13**	-	0.05	-	0.05	-	2
Mercury	mg/L	< 0.0002	< 0.0002	<0.00020	< 0.0002	< 0.0002	<0.00020	< 0.0002	<0.00020						
Molybdenum	mg/L	**0.04**	**0.041**	**0.035**	**0.023**	**0.022**	**0.016**	0.0056	0.0058	-	-	-	-	-	0.01
Nickel	mg/L	< 0.0050	< 0.0050	0.0055	< 0.0050	< 0.0050	<0.0050	< 0.0050	<0.0050						
Potassium	mg/L	4.7	4.9	6.6	4.2	4.3	7.9	16	17	-	-	-	-	-	-
Selenium	mg/L	< 0.020	< 0.020	<0.020	< 0.020	< 0.020	<0.020	**0.025**	**0.028**	0.05	-	0.05	-	-	0.02
Silica (SiO2)	mg/L	31	32	40	33	33	38	46	43	-	-	-	-	-	-
Silicon	mg/L	14	15	19	15	15	18	21	20	-	-	-	-	-	-
Silver	mg/L	< 0.0050	< 0.0050	<0.0050	< 0.0050	< 0.0050	<0.0050	< 0.0050	<0.0050						
Sodium	mg/L	**300**	**310**	**330**	**220**	**230**	**260**	**380**	**430**	-	-	-	-	-	69
Strontium	mg/L	0.114	0.118	0.176	0.051	0.0509	0.162	2.47	2.48	-	-	-	-	-	-
Thallium	mg/L	< 0.020	< 0.020	<0.020	< 0.020	< 0.020	<0.020	< 0.020	<0.020						
Tin	mg/L	< 0.010	< 0.010	<0.010	< 0.010	< 0.010	<0.010	< 0.010	<0.010						
Titanium	mg/L	< 0.010	< 0.010	0.0289	< 0.010	< 0.010	<0.0100	< 0.010	<0.0100						
Vanadium	mg/L	< 0.010	< 0.010	<0.010	< 0.010	< 0.010	<0.010	< 0.010	<0.010						
Zinc	mg/L	0.015	0.017	0.012	0.027	0.027	0.011	0.024	<0.0050		5		5		2

Note: Values shown in bold print exceed one or more water quality limits shown on right.
[a] Water quality limits for detected constituents summarized from A Compilation of Water Quality Goals, August, 2003, Regional Water Quality Control Board, Central Valley Region
[b] California Department of Health Services
[c] U.S. Environmental Protection Agency
[d] Primary Maximum Contaminant Level
[e] Secondary Maximum Contaminant Level
[f] California Office of Environmental Health Hazard Assessment Public Health Goal in Drinking Water
[g] Agricultural Water Quality Limits from Ayers, R.S. and D.W. Westcot, Water Quality for Agriculture, Food and Agriculture Organization of the United Nations - Irrigation and Drainage Paper No. 29, Rev. 1, Rome, 1965 as summarized in A Compilation of Water Quality Goals, August, 2003
[h] mg/L = milligrams per liter

Data from groundwater samples collected from monitoring well MW-3 are consistent with reported data for the CalPeak Panoche well located approximately 2,000 feet northeast of the PEC site. The CalPeak Panoche well is screened from 440 to 500 feet bgs and the filter pack extends from 20 to 500 feet bgs. The well is completed within the semi-confined aquifer. TDS, sulfate, hardness, and silica concentrations reported for a groundwater sample from the well are 3,400 mg/L, 1,900 mg/L, 1,500 milligrams equivalent calcium carbonate (mg equiv. $CaCO_3$), and 47 mg/L, respectively (Starwood, 2006). All of these concentrations are higher than those reported for PEC monitoring well MW-3, which is likely the result of the well producing lower quality groundwater from higher elevations within the semi-confined aquifer. A supply well completed within the semi-confined aquifer at the PEC site would be expected to produce similar water to the CalPeak Panoche well.

Sulfate concentrations exceeding 1,500 mg/L and hardness greater than 1,200 mg equiv. $CaCO_3$ are of particular concern for operation of the PEC. The sulfate and hardness concentration limits for the cooling tower design are 900 mg/L and 500 mg equiv. $CaCO_3$, respectively. Significant pretreatment to reduce concentrations of these constituents would be required prior to using the groundwater in the plant, even for a single cooling cycle.

Cycling cooling water multiple times is fundamental to the design of the PEC. Once-through cooling would cause efficiency losses of about 1.5 MW per unit because the heat rejection system of the plant would require redesign to incorporate an additional heat exchanger. Further, fewer cycles of cooling associated with use of water from the semi-confined aquifer would require more water to be extracted, treated, used for cooling, and injected as waste. Treatment and reuse of this cooling water to allow additional cycles of concentration would not be economically feasible because initial concentrations of sulfate and other constituents in the groundwater are high and would be further concentrated by the cooling process.

The only effective pre-treatment method is a lime softening system to remove suspended and dissolved solids, hardness, and alkalinity. The pretreatment system would need to be sized for the entire plant supply of 1,254 gallons per minute (gpm). This design would require extensive treatment of all water, including 591 gpm (47% of the supply) that will evaporate in the cooling tower. Industrial lime softening systems are designed for continuous operation and take approximately 24 hours to start up. They are unsuitable for start-stop operation. Therefore a 2,000,000-gallon capacity treated water storage tank would be required to provide start-up water while the lime softening system is brought on line. In the event tank contents are depleted during plant operations, the lime and soda ash softening system would require a one- to two-day restart process. Incorporation of a lime softening system would incur environmental impacts related to the transport, delivery, and storage of lime and soda ash as well as the unloading, transport, and delivery (to landfill) of sludge. [Refer to section 4.2.1.)

Incorporation of a lime softening system to treat sulfate, hardness, and alkalinity at the levels encountered in groundwater within the semi-confined aquifer underlying the PEC is incompatible with the plant design and PG&E requirements that mandate the plant to be up to full load in 10 minutes. Further, this pretreatment system would cost approximately $20M to install. Annual operations and maintenance costs for this Alternative are estimated to be $3.2M. The PEC cannot sustain these added costs and remain viable under the pricing model that was used to secure the PG&E contract.

3.2.3.2 Semi-Confined Aquifer Water Availability

A reliable supply of groundwater capable of producing approximately 1254 gpm of raw water is required for the PEC during average plant operations. Groundwater availability within the semi-confined aquifer was assessed using the steady-state groundwater flow model prepared for the PEC site. The model incorporated aquifer hydraulic conductivity parameters specific to the shallow aquifer estimated using slug test data from monitoring well MW-3 at the PEC. Slug tests are not generally as accurate as performing a long-term pumping test, but are an efficient method to determine aquifer properties and can be used to estimate the hydraulic conductivity of the formation in the immediate vicinity of the well screen.

Slug tests were conducted in the well using the following method. The static water level was measured using an electronic water level meter and a pressure transducer was installed in the well. Four slugs, ranging from 1 liter (L) to 18.9 L of deionized water, were injected through tubing that was inserted inside the well and suspended close to the water surface to reduce splashing. Changes in water-level data were recorded with the pressure transducer and monitored in real time at the ground surface. Each test was terminated after the water level had recovered to nearly the original static water surface measurement. Changes in water level data were analyzed using the Unconfined/Confined High Conductivity Bouwer-Rice Solution (Springer and Gelhar, 1991), the Confined - Hvorslev Model (Butler, 1997) and the Uffink method for oscillation test data to estimate a value of hydraulic conductivity (K) for the aquifer. Data from the smallest (1 L) and largest (18.9 L) slugs were not used in the analysis because the slugs were too small and took too long to inject, respectively. The hydraulic conductivity estimates ranged from 15.8 to 27.6 feet/day, which is within the normal range for the silt and sand semi-confined aquifer material encountered within the semi-confined aquifer (Freeze and Cherry, 1979). This site-specific hydraulic conductivity value range was incorporated into the steady-state groundwater model. Hydraulic conductivity is a normalized variable that describes the rate at which water can move through a given area in an aquifer and is a basic parameter used in groundwater flow modeling (URS, 2007a).

A production well with a 250-foot screened interval was added into the model to simulate operation of a supply well within the semi-confined aquifer. The pumping rate design was assumed to be 1,254 gpm over a 5,000-hour period (the maximum annual operation period of the PEC), which equates to an annualized rate of approximately 642 gpm in the steady state model. The model indicates that sufficient simulated groundwater production from the semi-confined aquifer would likely adversely impact wells screened in the semi-confined aquifer within a one-mile radius of the PEC. The predicted radial extent of a 10-foot drawdown impact is approximately 2,640 feet and the predicted radial extent of an 8-foot drawdown impact is 5,280 feet. Progressively smaller drawdown would extend greater distances from the PEC.

As many as 12 existing or abandoned water wells have been identified within a one-mile radius of the PEC. Most of these wells have been abandoned, have collapsed, or are monitoring wells not used for groundwater production. The closest known supply well completed in the semi-confined aquifer is the CalPeak Panoche Plant well. The estimated yield of the well was 100 gpm based on a 1-hour test with no drawdown reported (Starwood, 2006). Based on the drawdown analysis, this neighboring supply well would likely be adversely impacted by approximately 10 feet of drawdown if a PEC supply well installed within the semi-confined aquifer was pumped at an annualized rate of 642 gpm. Any drawdown in neighboring wells could be considered adverse because it would increase operational costs for the wells. Assuming an overall efficiency of 65%, power requirements for pumping a well would increase about 0.39 kilowatts per foot of drawdown. Based on PG&E agricultural rates (Schedule AG-1, Rate B, Effective 9/1/2006), pumping costs would increase about $0.292 per acre foot of water pumped per foot of drawdown.

An additional factor in groundwater availability is the reliability of the PEC supply wells. Relatively high concentrations of sulfate, along with other minerals dissolved in the semi-confined aquifer groundwater, would be expected to cause significant encrustation, corrosion, and abrasion of pumps and related equipment leading to above average repair and maintenance requirements and costs. The potential for downtime of the supply wells and possibly the PEC itself would increase if the semi-confined aquifer was the selected water supply alternative. Sufficient quantities of groundwater for the PEC appear to be present in the semi-confined aquifer, although production operations may have some impact on neighboring well production. ***Therefore, obtaining production water from the semi-confined aquifer was eliminated because the low quality water is expected to adversely affect the site operational costs and may negatively impact the production operations of nearby wells.***

3.2.3.3 Confined Aquifer Water Quality

Groundwater samples collected from on-site monitoring wells screened from 1,100 to 1,120 feet bgs (MW-2) and 1,302 to 1,322 feet bgs (MW-1) indicate that groundwater quality within the confined aquifer underlying the site is negatively impacted by dissolved minerals (see Tables 3.1 and 3.2). Detected constituents in the groundwater samples collected from both the upper and lower portions of the confined aquifer were compared to water quality limits for drinking water and agricultural use published by the Central Valley RWQCB (RWQCB, 2003). The comparison was intended to indicate the suitability of the sampled groundwater for use as drinking water or agricultural water. Based on the analytical reports, the sampled groundwater appears to be a poor candidate for use as a drinking or agricultural water supply without treatment. The reported turbidity value may also exceed EPA and CDHS primary MCLs for drinking water, but may have been negatively influenced by air-lift pumping. Specific conductance and pH values, as well as TDS and iron concentrations, exceeded CDHS and/or EPA Secondary MCLs for drinking water and agricultural water quality limits. Detected concentrations of sulfate as SO_4 exceeded EPA Secondary MCLs for drinking water. Boron, molybdenum, and sodium concentrations also exceeded agricultural water quality limits.

While treatment would be required prior to using the water for cooling at the PEC, the treatment required would be at a lower cost than if the water was to be used for drinking water. Treatment of the water from the supply wells would be as described in the AFC and subsequent CEC data request responses and is a feasible method to supply water for the PEC. The concentrations of strontium, barium, silica, and iron are at levels that may cause fouling and scaling problems for the cooling towers.

3.2.3.4 Confined Aquifer Water Availability

Well yields within the Westside Subbasin of the San Joaquin Valley Groundwater Basin average 1,100 gpm and average from 600 to 1,800 feet in depth (DWR, 2004). Lithologic and geophysical logging of sedimentary deposits underlying the site indicates that geologic and hydrogeologic properties of the semi-confined and confined aquifer are consistent with the surrounding area and the aquifers should be capable of producing average groundwater yields.

As stated in the response to CEC Data Request 47, the groundwater model prepared for the PEC site indicates that a supply well pumping groundwater from the confined aquifer at an annualized rate of 750 gpm would not impact groundwater elevations within the confined aquifer or the overlying semi-confined aquifer. The model indicates that even if the annualized pumping rate was increased to 1,000 gpm, which is 33% higher than the proposed pumping rate, no noticeable drawdown occurs. An additional model run indicates that limited drawdown (i.e., less than 2.5 feet) occurs when the well is pumped at 2,000 gpm.

Sufficient quantities of groundwater appear to be present in the confined aquifer to meet PEC operational demands. Groundwater within the confined aquifer appears to present a reliable water supply suitable for the PEC based on previous use of this water for large-scale agricultural irrigation supply prior to delivery of surface water to the area.

Therefore, obtaining production water from the confined aquifer was retained for further consideration because the water, although not drinking-water quality, is of sufficient quality for PEC operations and there is an adequate supply with no potential negative impact on neighboring groundwater production operations.

3.3 Project Water Supply – Comparison of Alternatives

Table 3.3 presents a summary of the evaluation of water supply alternatives.

Table 3.3. .Summary of Water Supply Alternatives Evaluation

Environmental & Economic Measure		**Test 1** Is the supply feasibly available at PEC?	**Test 2** Will the alternative satisfy California Water Policy?	**Test 3** Is it technologically sufficient to guarantee high safety reliability?	**Test 4** Other Environmental Impacts	**Test 5** Capital Cost *	**Test6** Operation and Maintenance Annual Cost
Alt1	Surface water	Failed. Location is not close enough.	Would fail.	—	—	—	—
Alt2	State water project	2 miles away	Failed. PEC is located out of the permitted SWP area.	—	—	—	—
Alt3	Federal CVP water	Passed	Failed. The use of portable water is inconsistent with CVP.	—	—	—	—
Alt4	Reclaimed water	Failed. Available reclaimed water is located at least 25 miles away.	Passed	Failed. Currently reclaimed water is not available in sufficient quantity.	Pipeline to the PEC site would be required.	—	—
Alt5	Agricultural water	Passed	Passed	Failed. Agricultural water is not available in sufficient quantity.	Additional pumps, storage facilities, pipelines would be required.	$10M	$1.1M

Environmental & Economic Measure		**Test 1** Is the supply feasibly available at PEC?	**Test 2** Will the alternative satisfy California Water Policy?	**Test 3** Is it technologically sufficient to guarantee high safety reliability?	**Test 4** Other Environmental Impacts	**Test 5** Capital Cost *	**Test6** Operation and Maintenance Annual Cost
Alt6	Upper aquifer groundwater	Passed. However, there may be long-term supply issues.	Passed	Failed. High TDS concentration. Water quality will not meet minimum requirements. Water pretreatment would be economically and environmentaly unsound.	Energy efficiency losses would be generated, transportation of large quantity of chemicals, and large quantity of waste disposal.	$20M	$3.2M
Alt7	Lower aquifer groundwater	Passed	Passed	Passed. Sufficient quality to meet the water supply requirement for PEC.		$8M	$300k
Alt8	Ocean water	Failed. PEC islocated too far from ocean.	—	—	Pipeline would be required	—	—

* Cost are calculated on a rough order of magnitude level

4.0 Wastewater Disposal

4.1 Wastewater Disposal - Guiding Principles

In September 2006 PEC filed an application with the EPA in San Francisco for a permit to drill and utilize underground injection well(s) for disposal of the project's wastewater. In addition to deeming the Application "complete", EPA has not communicated any technical concerns with this Application. EPA has communicated to CEC and to PEC that the UIC application will be approved within one year or less from the filing date. CEC has expressed concern that the timing of EPA's issuance of the UIC permit (i.e., September 2007) and the PEC AFC process schedule set forth at the December 13, 2006 Informational Hearing. Given that UIC technology in general presents very low environmental risk, PEC believes that the CEC should consider proceeding with PSA and FSA by utilizing a "condition" that the UIC permit be issued to PEC prior to final approval of the AFC by the CEC.

The CEC staff has indicated that they would prefer to see the results of drilling in order to see if the deep well injection plan is feasible. There is no need to question EPA's determination; the CEC should give due deference to the federal government approval and accept the results of the EPA review of the filed application.

Alternatives to a proposed action are to be considered by the decision-maker which would "substantially lessen any of the significant effects of the project." [CEQA Guidelines, 14 CCR 15126.6(a)]. The deep injection well (UIC) offers the best wastewater alternative as it does not result in any significant environmental impacts; therefore, alternatives to the UIC wastewater disposal method are not required. However, PEC recognizes that the CEC must make its independent conclusion, and for that reason, additional information on wastewater disposal alternatives is provided below.

4.2 Wastewater Discharge - Alternatives

4.2.1 Zero Liquid Discharge

A zero liquid discharge (ZLD) power plant requires pretreating the process water discharge to remove the mineral content and recirculate the resulting liquid back into the process. For the PEC project, a ZLD system would be based on treating the maximum daily wastewater production anticipated and assumes that all plant wastewater, except sanitary wastewater and discharge from the oil/water separators, is routed to the cooling tower. The latter wastewater streams are assumed to be disposed of by leach field and land disposal, respectively.

The ZLD design concept is comprised of two major subsystems:

- Cooling tower blowdown pretreatment and concentration; and
- Brine crystallization and solids handling.

The cooling tower blowdown and concentration subsystem would include a High Efficiency Reverse Osmosis (HERO™) system for volume reduction. This process requires extensive pretreatment to remove suspended solids, hardness, alkalinity, and silica. The first step of the process treatment is lime and soda ash softening of a sidestream of the circulating water. The lime and soda ash softener is unsuitable for start-stop operation. Therefore a 1,000,000-gallon capacity cooling tower blowdown storage tank would be required to allow the lime and soda ash softening process to continue operating at steady state even when the plant is not operating. In the event tank contents are depleted during a plant outage, the lime and soda ash softening process would be shut down and would require one to two days for an orderly restart.

Approximately 400 gpm of the softened water from the side stream lime and soda ash softening process would be further treated by the HERO™ system. The HERO™ system should be able to recover approximately 90% of this waste stream with the reject stream going to the brine crystallization and solids handling subsystem.

The brine crystallization and solids handling subsystem was assumed to be ~ 40 gpm based on continuous operation and 90% recovery by the HERO™ process. Distillate from the crystallizer would be returned to the cooling tower. A portion of the recirculating slurry of salt crystals would be sent to the filter press for dewatering. Filtrate from the filter press would be returned to the crystallizer. The salt cake would be dumped into a hopper for off-site disposal via a truck transporter.

The ZLD system is complex and labor-intensive, as it requires continuous operator attention while in service. It is estimated that PEC would need to double its proposed staff from 12 to 24 personnel to be able to operate and maintain the ZLD system.

The lime softening, HERO™ and ZLD systems are designed to be continuous operations that take approximately 24 hours to start up. This is incompatible with the plant design and PG&E requirements that the plant be up to full load in 10 minutes. Keeping the ZLD system operational at all times, even when the power plant is not operational, changes the plant economics and makes it economically infeasible.

The lime softening system includes environmental impacts related to the transport, delivery and storage of lime and soda ash as well as the unloading, transport, and delivery (to landfill) of sludge.

In summary, the ZLD system is not suited to the needs of the PEC project for the following reasons:

1. It increases the capital costs of the project by about $21 million;
2. It increase the annual operating cost of the plant by about $2.4 million;
3. It handicaps the operating requirements of the plant by limiting plant readiness on demand; and
4. It adds to environmental issues due to increase in truck traffic and handling of additional chemicals and sludge hauling to a landfill.
5. The PEC cannot sustain these added costs and remain viable under the pricing model that was used to win the PG&E supply bid.

Numbers 1 and 2 above impact the economic feasibility of the project and Number 3 limits PEC ability to meet contractual requirements of the Power Purchase Agreement (PPA) and customer (PG&E) needs. ***Therefore, ZLD is economically unsound and environmentally undesirable..***

4.2.2 Evaporation Pond

An evaporation pond becomes viable if the waste stream can be reduced to a manageable quantity. However, the PEC waste stream is 394 gpm and would need to be reduced with a lime softening process and HERO™ system. As discussed earlier, this process is expensive and is not compatible with intermittent operations that must be able to achieve full load within 10 minutes. Discharge of the full waste stream would require a lined pond in excess of 100 acres, costing over $30M. PEC believes this is environmentally undesirable for wildlife due to the selenium concentrations in the area. Utilization of land for an evaporation pond went against the project objective to minimize conversion of agricultural land due to Williamson Act considerations. In addition, the landowner, Baker Farming, was not interested in making such additional acreage available for the project.
Therefore the evaporation pond was eliminated because it is economically unsound and environmentally undesirable.

4.2.3 Deep Injection Well

The application of a deep injection well system for facilities that generate brine requires optimum hydrogeologic conditions that can receive the injected waste without impacting potential groundwater resources within the site vicinity. Factors contributing to these optimum conditions include: the zone of groundwater injection is isolated from potential groundwater resources, the groundwater injection zone provides adequate storage for the injected waste, and formation water quality of the injection zone is low and not a potential groundwater resource. The Underground Injection Control Permit Application, submitted by PEC, provided a detailed assessment of these factors, which are summarized below.

- **Isolated Zone of Groundwater Injection**

  The PEC project site is located in the San Joaquin Basin, which contains a number of confining zones capable of protecting underground sources of drinking water. The proposed zone of groundwater injection beneath the site is within Eocene sands (Laguna and Cima) that extend from approximately 4,800 to 5,600 feet beneath the site. The sands are overlain by a laterally extensive, 900+ feet-thick shale sequence known as the Kreyenhagen Formation. This relatively impervious shale sequence acts as a confining zone that prohibits the vertical migration of high saline groundwater within the Eocene sands up to the shallower lower saline groundwater. In addition, there is no known faulting within the area of proposed injection that might affect the integrity of the Kreyenhagen Formation.

- **Adequate Storage for Groundwater Injection**

  Based on a detailed assessment of the Eocene sands at the nearby Cheney Ranch Gas Field, the injection zone transmissivity (assuming a minimum injection zone thickness of 500 feet) is approximately 765 ft^2/day with a corresponding storage coefficient of 0.00096. A detailed analysis of these conditions indicates that if PEC were to inject 765,000 gallons per day (which is more than the estimated volume for PEC operations), then the radius of wastewater spreading would be approximately ½-mile after 30 years of full-time operation. The corresponding pressure increase at this distance would be about 50 pounds per square inch or 115 feet of groundwater head, which is contained well within the overlying 900+ feet thick Kreyenhagen Formation. On the basis of these results, the proposed injection zone provides more than adequate storage for 30+ years of continuous operation with no potential impact to local groundwater supplies.

- **Injection Zone Formation Water is Not a Groundwater Resource**

  Analyses of groundwater collected from Eocene sands in the vicinity of the PEC site indicate that TDS are on the order of 22,000 mg/L. This concentration is well above the State Water Resources Control Board Resolution 88-63 usable municipal or domestic water supply limit of 3,000 mg/L. It is also above the maximum proposed injection concentration of 5,000 to 7,000 mg/L. Therefore, existing groundwater in the proposed injection zone is not considered a groundwater resource and will not be degraded by the proposed injection program.

It should be noted that several facilities meeting the above hydrogeologic factors have successfully implemented deep injection wastewater disposal using UIC Class I non-hazardous wells. One example is the Elk Hills power facility that currently injects over 1M gallons per day of brine into a relatively shallow injection zone. In addition, the Hilmar and Manteca cheese facilities have successfully installed and utilized UIC Class I non-hazardous injection wells for brine disposal under very similar hydrogeologic conditions as the PEC site.

The implementation of a deep injection well system at the PEC site would consist of two injection wells constructed to about 5,600 feet bgs with a continuous injection rate of about 284,000 gallons per day per well during site operations. PEC will operate as a peaker plant with an equivalent full-time operation of about four months per year. The installation cost for two wells is approximately $3M and the corresponding Operation and Maintenance costs are on the order of $100,000 per year.

Therefore, the Deep Injection Well alternative is the preferred method of wastewater disposal for the PEC.

4.2.4 Disposal to Wastewater Treatment Plant

As stated in the AFC, a POTW is not available in the vicinity of the PEC. The two nearest POTWs are 16 and 25 miles from the site (see Section 3.2.5 above) and, based on existing capacities, would be unable to accept another 0.57 MGD of wastewater. Both of these plants either have no current capacity to accept additional load or the projected load for the immediate future will leave them without extra capacity due to growth in the community.

This alternative was dropped from further consideration based unavailability of capacity and distance for the project site.

4.2.5 Surface Discharge

Based on the characterization provided in Table 5.5-13 of the AFC, wastewater from the PEC will not be suitable for surface discharge as it does not meet the water quality objectives specified in the Central Valley Region Basin Plan as shown in Table 4.1. Further, it is expected that the wastewater discharges will also not meet the requirements of the California Toxics Rule. Therefore, it has been determined that surface discharge will not be a feasible alternative for disposal of wastewater from the PEC.

Table 4.1 Comparison of Panoche Wastewater Characteristics and Basin Plan Objectives

Water Quality Parameter	Combined Flow Estimated Wastewater Characteristics	Basin Plan Objective
Boron	2.3 mg/L	1.0 mg/L
Chloride	250.7 mg/L	175 mg/L
Iron	1.2 mg/L	0.3 mg/L
pH	6.0 – 8.5	6-5 – 8.3 (without changing more than 0.3 units from normal ambient pH at any time)
TDS	1,668.2 mg/L	500 mg/L
Sulfate	536.8 mg/L	250 mg/L

Table References:

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Central Valley Regional Water Quality Control Board. 2004. Recommended Numerical Limits to Apply to Water Quality Objectives. Available at: http://www.waterboards.ca.gov/centralvalley/available_documents/index.html#WaterQualityGoals

4.2.6 Offsite Treatment

The PEC will produce up to 567,400 gallons of wastewater per day while the plant is in operation. We could not identify a facility in the vicinity of the project site that can accept this amount of water for treatment.

Due to the large volume of wastewater, transport to a remote location for disposal was rejected due to economic, air quality and traffic considerations.

4.3 Project Wastewater Disposal – Comparison of Alternatives

Table 4.2 presents a summary of wastewater disposal alternatives.

Table 4.2. Wastewater Disposal Alternatives Summary

Environmental & Economic Measure		**Test 1** Is the wastewater disposal feasibly available at PEC?	**Test 2** Will the alternative satisfy applicable laws, ordinances, regulations and standards?	**Test 3** Is it technologically sufficient to guarantee high safety reliability?	**Test 4** Other Environmental Impacts	**Test 5** Capital Cost	**Test6** Operation and Maintenance (annual)
Alt1	Zero Liquid Discharge System	Passed	Passed	Failed. Low reliability, high energy ratings, high capital and maintenance costs, landfill disposal of wastes.	Transportation of large quantities of chemicals on site and waste hauling off-site.	$16M	$2.4M
Alt2	Evaporation pond	Passed	Failed. High selenium precludes permitting of such facility.	—	—	$30M	—
Alt3	Deep injection well	Passed	Passed	Passed	Passed	$3M	$100k
Alt4	Disposal to wastewater plant	Failed. Sewer is not available in the vicinity of PEC.	—	No POTW capacity available currently.	Pipeline to POTW will be required.	—	—
Alt5	Surface discharge	Passed	Failed. The quality of wastewater cannot meet federal discharge limitations.	—	—	—	—
	Offsite treatment	Passed	Passed	Failed. No off-site facility identified for this purpose.	Water will need to be transported off-site.	—	—

5.0 Summary and Conclusions

The PEC is a peaking and load shaping project that has certain requirements that have to be met without which the economic viability of the plant is compromised. One of the prime considerations of such a project is to provide electric power to the grid on very short notice to meet high demands from retail consumers and to comply with the terms of the PPA.

Since the shaping resources are expected to provide flexible operating capacity with energy production that can vary on a daily, seasonal, and annual basis depending on demand, and the cost of producing electricity, the operational requirements of load shaping products such as PEC vary, as do the operating economics of the plants.

PEC has to meet the essential requirements of the PPA to be able to dispatch electricity from "cold iron" to full load within 10 minutes. To fulfill these requirements, the project has to have continuous, reliable and good quality water resources for plant cooling/process applications and has to have in place a reliable and environmentally sound wastewater disposal option for the rejected water from the plant.

In this Technical Memorandum, we have provided supplementary information to justify the alternatives for both water supply and wastewater disposal. We have considered the full universe of available alternatives and by a process of elimination arrived at the best alternative for water supply and water disposal. In the process, we have followed rules and guidelines applicable for this process, considered environmental concerns, and applied criteria to help eliminate alternatives that do not serve the project objectives or run counter to water quality objectives of the state.

The selection of the confined lower aquifer presents the best option among the viable water source alternatives considering overall project and locale, environmental, health and safety, and economic performance.

UIC offers the best option for wastewater management and disposal among the wastewater alternatives considering overall project and locale environmental, health and safety, and economic performance.

6.0 References

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TECHNICAL MEMORANDUM
PANOCHE ENERGY CENTER

SUPPLEMENTAL DISCUSSION OF WATER SUPPLY AND WASTEWATER DISCHARGE ALTERNATIVES

Submitted to

The California Energy Commission

March 23, 2007

Submitted by

Panoche Energy Center, LLC

With support from

URS

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March 23, 2007

James W. Reede, Jr., Ed.D.
Energy Facility Siting Project Manager
California Energy Commission
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Sacramento, CA 95814

RE: Panoche Energy Center – Supplemental Discussion of Water Supply and Wastewater Discharge Alternatives

Dear Dr. Reede:

On behalf of Panoche Energy Center, LLC (PEC), URS Corporation respectfully submits the attached Technical Memorandum entitled "Supplemental Discussion of Water Supply and Wastewater Discharge Alternatives." This Technical Memorandum has been developed to address comments and questions generated by the CEC staff in response to the previously submitted Technical Memorandum (*dated March 2, 2007*).

The intent of this memorandum is to provide additional information on cost and regulatory definitions that were presented in the Technical Memorandum dated March 2, 2007. This memorandum also provides supplementary information to justify the use of water from the lower confined aquifer for cooling at the PEC and the use of deep injection wells for the disposal of process wastewater generated from the facility.

PEC appreciates this opportunity to provide the CEC with this supplemental technical memorandum. Given the critical nature of water and wastewater relative to both the CEC AFC process and the overall success of the PEC project, I ask that you and Staff review this Technical Memorandum prior to our meeting on April 13, 2007. As a result, the PEC team hopes that Staff's concerns will have been answered. I appreciate your consideration of this Technical Memorandum, and look forward to our discussions in its regard.

Sincerely,

Margaret M. Fitzgerald
Program Manager

Attachment
Cc: Eileen Allen, CEC
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Technical Memorandum
Panoche Energy Center

Supplemental Discussion of Water Supply and Wastewater Discharge Alternatives

March 23, 2007

This Technical Memorandum has been developed to address comments and questions generated by the California Energy Commission staff in response to the previously submitted Technical Memorandum (*dated March 2, 2007*). The subsequent sections of this Technical Memorandum will address the following topics:

- A cost comparison between different water sources for use as process water for the project. More specifically, a comparison between the uses of upper-level, semi-confined aquifer water wells versus lower-level, confined aquifer water wells.

- A cost comparison between different wastewater discharge alternatives. More specifically, a comparison between the uses of deep well injection versus a zero liquid discharge system, while using confined aquifer as the water supply.

- A discussion of the definitions of fresh water and brackish water, and identification of water sources for Panoche Energy Center (PEC) based upon those definitions.

The intent of this memorandum is to provide additional information on cost and regulatory definitions that were presented in the Technical Memorandum dated March 2, 2007. This memorandum also provides supplementary information to justify the use of water from the lower confined aquifer for cooling at the PEC and the use of deep injection wells for the disposal of process wastewater generated from the facility.

Note: Follow-up information for the Technical Memorandum on this subject sent to CEC on March 2, 2007.

1.0 Background

A variety of options were examined to determine the most appropriate water source and wastewater disposal methods for the Panoche Energy Center (PEC). The various options were assessed and presented through the Application for Certification (AFC) submission and in an initial Technical Memorandum (March 2, 2007). After an evaluation and discussion of the initial Technical Memorandum (*meeting with California Energy Commission [CEC] staff on March 7, 2007*), CEC staff requested further information on the alternative water/wastewater options examined for the PEC. The basis of the CEC request is to obtain a clear determination that the requirements presented by Resolution No. 75-58 are being properly recognized and upheld by the PEC.

In order to comply with the CEC's requests for comparative cost analysis, four water/ wastewater options were examined for PEC. These different options are listed below:

- **Option A**
  - Water Source
    - 70% from the lower confined aquifer
    - 30% from Baker Farming filter backwash
  - Wastewater Disposal Method
    - Deep Injection Well
- **Option B**
  - Water Source
    - Lower Confined Aquifer
  - Wastewater Disposal Method
    - Deep Injection Well
- **Option C**
  - Water Source
    - Lower Confined Aquifer
  - Wastewater Disposal Method
    - Zero Liquid Discharge (ZLD) system
- **Option D**
  - Water Source
    - Upper Semi-Confined Aquifer
  - Wastewater Disposal Method
    - Deep Injection Well

The remainder of this Technical Memorandum is organized as follows. Section 2.0 compares the estimated cost of Option B with Options A and D using the same Deep Well Injection method as wastewater disposal. Section 3.0 compares the estimated cost of a ZLD system (Option C) with the Deep Well Injection (Option B) using the same confined aquifer water supply source. Section 4.0 discusses the further investigation that was conducted to clarify the definitions of fresh water and brackish water. Through the clarification of these terms, the PEC will demonstrate that all requirements established in Resolution 75-58, and other CEC guidance on the subject of water usage in power plants, are being adhered to. The comparisons presented below demonstrate that Option B is the most economically sound alternative for the PEC project (see conclusions in Section 5.0).

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2.0 Water Supply Selection Based Upon Cost Analysis Semi-confined Aquifer Versus Confined Aquifer

The confined aquifer water is the proposed source for PEC because of its relatively lower capital and Operating and Maintenance (O&M) cost, as well as lower waste sludge generation and energy consumption. Compared to using semi-confined aquifer water or a combination of agriculture water reuse and confined aquifer, the exclusive use of confined aquifer water is the most economically and environmentally sound option. Costs for the various options are listed in the Table 2-1.

Table 2-1. Cost Comparison

	A[1] Comparative Evaluation	B Proposed	D Comparative Evaluation	Remarks
	Baker Water well backup	Confined aquifer Wells / Reverse Osmosis (RO) / Injection Wells	Semi-confined aquifer Wells / RO / Injection Wells	
Water TDS	280 ppm	1000 ppm	3000 ppm	Water in options B and D can be described as brackish (see Section 4.0)
Capital Cost				
Paid to Baker for the use of land and water	$ 500,000			
Clarifier / Filter	$ 1,500,000		$ 4,000,000	
RO/ System	$ 3,500,000	$ 3,500,000	$ 7,500,000	
Production Wells	$ 1,500,000	$ 1,500,000	$ 1,500,000	
Injection Wells	$ 3,000,000	$ 3,000,000	$ 3,000,000	
Misc filters, pumps, systems			$ 4,000,000	
Water / Waste Capital Cost	$ 10,000,000	$ 8,000,000	$ 20,000,000	Option B has the lowest capital costs
Variable Costs 5000 Hours				
Aux Power (above base) FIXED	$ 100,000		$ 400,000	600 kw, 800kw
Water Supply	$ 500,000	$ 50,000	$ 50,000	
Water Discharge	$ 100,000	$ 50,000	$ 50,000	
Chemicals (above base)	$ 100,000		$ 1,560,375	
Demin Trailers	$ 200,000	$ 200,000	$ 200,000	
Operators (Labor above base)	$ 150,000		$ 670,000	
ZLD/ lime System Maintenance			$ 300,000	
Total O&M	$ 1,150,000	$ 300,000	$ 3,230,375	Option B has the lowest annual O&M costs
Increase Capital (above base)	$ 2,000,000	$ Base	$ 12,000,000	
Increase O&M Annual (above base)	$ 850,000	$ Base	$ 2,930,375	

[1] Baker Farming recovers backwash water at a volume equivalent to about one-third of the water supply needs of the PEC, but not necessarily consistent with the operation of the PEC. Therefore, this option is the same as our base option (see Option B) with about 30% of the water provided by Baker as filter backwash water. The system requires the installation of additional equipment to treat the surface water stream as well as base equipment to treat well water. The following differences are relative to Option B.

Capital- $1.5M for clarifier and $500K payment to Baker for installation of collection piping. Estimates derived from engineering cost manuals and from experienced power plant operators

O&M – There would be water supply charges, additional chemicals, aux power to run the clarifier and two additional operators.

Water from the semi-confined aquifer contains the following minerals that will affect plant economics:

1. Sulfate concentrations exceeding 1,500 milligrams per liter (mg/L) (i.e., three times higher than confined aquifer); and

2. Hardness greater than 1,200 milligrams (mg) equiv calcium carbonate ($CaCO_3$) (20 times higher than confined aquifer).

These water quality parameters are of particular concern for operation of the PEC. The sulfate and hardness concentration limits for the cooling tower design are 900 mg/L and 500 mg equiv. $CaCO_3$, respectively. Therefore, significant pretreatment to reduce the concentration of these constituents would be required. In addition, the total dissolved solids (TDS) concentration in the semi-aquifer is three times higher than that of the confined aquifer, which imposes a high pressure requirement of the reverse osmosis (RO) system. As a result, the total capital cost will increase by about $12M and the annual O&M will increase over $2.9M using the semi-confined aquifer compared to confined aquifer water.

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3.0 Wastewater Disposal Method Selection Criteria Based Upon Cost Analysis, Zero Liquid Discharge Versus Deep Well Injection

As discussed in the previous Technical Memorandum (March 2, 2007), the Deep Injection Well alternative is the preferred method of wastewater disposal for PEC because it meets the following hydrogeological factors:

- Isolated Zone of Groundwater Injection;
- Adequate Storage for Groundwater Injection; and
- Injection Zone formation Water is not a Groundwater Resource.

In addition, the Deep Injection Well alternative is also more economically sound than the implementation of a ZLD system. The installation cost for two wells is approximately $3M and the corresponding O&M costs are on the order of $100,000 per year. A breakdown of some of the associated costs with each option is provided in Table 3-1.

Table 3-1. Cost Breakdown for Each Option

	B Proposed	C(2) Comparative Evaluation
	Confined aquifer Wells / RO / Injection Wells	Confined aquifer Wells / RO / ZLD
Water TDS	1000 ppm	1000 ppm
Capital Cost		
RO/ System	$ 3,500,000	$ 3,500,000
Ground Wells	$ 1,500,000	$ 1,500,000
Injection Wells	$ 3,000,000	$ -
ZLD		$ 16,000,000
Misc filters, pumps, systems		
Water / Waste Capital Cost	$ 8,000,000	$ 21,000,000(3)
Variable Costs 5000 Hours		
Aux Power (above base) FIXED		$ 300,000
Water Supply	$ 50,000	$ 50,000
Water Discharge	$ 50,000	$ 50,000
Chemicals (above base)		$ 520,125
Demin Trailers	$ 200,000	$ 200,000
Operators (Labor above base)		$ 800,000
ZLD/ lime system Maintenance		$ 500,000
Total O&M	$ 300,000	$ 2,420,125(4)
Increase Capital (above base)	$ BASE	$ 13,000,000
Increase O&M Annual (above base)	$ BASE	$ 2,120,125

(2) This option uses a ZLD system versus Deep Injection Wells. The ZLD system requires the installation of additional equipment for lime softening/ High Efficiency Reverse Osmosis (HERO) and a crystallizer. Labor estimates and capital and O&M estimates are derived from consultation with individuals at the Magnolia power plant as well as estimates from Bibb Engineering.
(3) Capital- Bibb Engineering developed a detailed estimate for $16.7M- attached
(4) O&M – An increase in aux power of 600 kW is anticipated. Chemicals to support the ZLD include lime soda ash and a number of specialty chemicals. This estimate is based upon actual cost from an operating power plant in Burbank, California (Magnolia Power Plant) cost of about

$2500 per day and includes sludge hauling and disposal. Labor is expected to increase by 12 operators as estimated by Bibb Engineering and confirmed by Magnolia Power Plant Project in Burbank, CA.

Operation of a ZLD system at the PEC plant requires pretreating the process water discharge to remove the mineral content and circulate the resulting liquid into the process cooling water system. Compared to the deep well injection system, ZLD is not suited to the technical or economic model of the PEC project for the following reasons:

1. It increases the capital costs of the project by about $13M;

2. It increases the annual operating cost of the plant by about $2.1M;

3. It handicaps the operating requirements of the plant by limiting plant readiness on demand; and

4. It adds to environmental issues due to increase in truck traffic and handling of additional chemicals and sludge hauling to a landfill.

A breakdown of cost estimates and assumptions for the ZLD option are presented in Section 3.1.

3.1 Zero Liquid Discharge Process Description and Cost Estimate

This section describes the conceptual design of an alternate plan for treatment of cooling tower blowdown to achieve ZLD at the PEC. The design is based on treating the maximum daily wastewater production anticipated and assumes that all plant wastewater except sanitary wastewater and discharge from the oil/water separators is routed to the cooling tower. The latter wastewater streams are assumed to be disposed of by leach field and land disposal, respectively.

The alternate design concept is comprised of two major subsystems:

- Cooling Tower Blowdown Pretreatment and Concentration; and
- Brine Crystallization and Solids Handling.

3.1.1 Cooling Tower Blowdown Pretreatment and Concentration

The cooling tower blowdown and concentration subsystem includes High Efficiency Reverse Osmosis (HERO™) for volume reduction. This process requires extensive pretreatment to remove suspended solids, hardness, and alkalinity. The first step is lime and soda ash softening of a sidestream of the circulating water. The lime and soda ash softener is unsuitable for start-stop operation. Therefore a 1,000,000 gallon capacity cooling tower blowdown storage tank is included in the plan to allow the lime and soda ash softening process to continue operating at steady state when the plant is not operating. In the event tank contents is depleted during a plant outage, the lime and soda ash softening process is shut down and will require 1 to 2 days for an orderly restart.

Approximately 300 gpm of the softened water from the side stream lime and soda ash softening process is further treated by the HERO™ system. The HERO™ system is expected to recover approximately 90% of this waste stream with the reject steam going to the Brine Crystallization and Solids Handling Subsystem.

The cooling tower blowdown and concentration subsystem is expected to consist of the following major equipment components:

- Cooling tower blowdown transfer pumps;
- One 100% capacity solids contact unit;
- One softened water clearwell;
- Two softened water transfer pumps;
- Complete chemical feed subsystems (lime, soda ash, sodium hypochlorite, coagulant, and polymer) each with two full capacity dosing pumps;
- Two 100% capacity pressure or gravity filters;
- Two full capacity air scour blowers;
- One full capacity filter backwash pumps;
- One full capacity sludge thickener;
- Two sets of full capacity sludge handling pumps;
- One full capacity filter press;
- Sulfuric acid feed subsystem;
- Sodium hydroxide feed subsystem;
- Two full capacity filtered water transfer pumps;
- Two 100% capacity weak acid cation (WAC) exchangers;
- WAC regenerant storage tank;
- Two WAC regenerant recycle pumps;
- Sodium bisulfite feed subsystem;
- Antiscalant feed subsystem;
- One full capacity degasifier with redundant air blowers;
- 1st stage HERO feed pumps;
- HERO cartridge filters;
- 1st stage HERO™ booster pumps;
- 1st stage HERO™ unit;
- 1st stage HERO™ reject tank;
- 2nd stage HERO™ feed pumps;
- 2nd stage HERO™ cartridge filters;
- 2nd stage HERO™ booster pumps;
- 2nd stage HERO™ unit;
- Permeate storage tank;
- Two full capacity permeate transfer pumps; and

- Brine storage tank (~5 days storage).

3.1.2 Brine Crystallizer and Solids Handling

The Brine Crystallization and Solids Handling subsystem will include the following major equipment components. The treatment capacity is assumed to be ~ 30 gallons per minute (gpm) based on continuous operation and 90% recovery by the HERO™ process.

- One crystallizer feed pump skid;
- One crystallizer distillate tank and pump skid;
- One crystallizer forced circulation heat exchanger;
- One full capacity crystallizer recirculation pump;
- One crystallizer flash tank;
- Antifoam dosing system with two pumps;
- One full capacity mechanical vapor compressor;
- One crystallizer brine storage tank;
- One crystallizer filter press;
- Two full capacity filter press feed pumps; and
- One filtrate tank and pump skid.

Distillate from the crystallizer is returned to the cooling tower. A portion of the recirculating slurry of salt crystals is sent to the filter press for dewatering. Filtrate from the filter press is returned to the crystallizer. The salt cake is dumped into a hopper for off-site disposal by others.

The ZLD system is complex and requires continuous operator attention while in service.

3.1.3 Waste Solids Production

The estimated volume of solids produced at maximum daily operating conditions is based on the following assumptions:

- 30 gpm HERO™ reject;
- Reject density ~9 pounds (lbs)/gallon;
- 50,000 parts per million (ppm) dissolved solids in HERO™ reject;
- Filter cake is 30% solids; and
- Filter cake density is 75 lbs/cubic feet

The "maximum day" filter cake production is estimated to be 865 cubic feet/day. The "average day" solids production is estimated to be 620 cubic feet/day. Annual solids production can be estimated by multiplying the average day production by the plant capacity factor. These estimates are preliminary and should be confirmed following final sizing of the ZLD system.

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3.1.4 Space Requirements

The space required is expected to be an area of about 120' x 180". The HERO™ system and all chemical feed and pump skids are assumed to be indoors, while solids contact clarifier, crystallizer body, filter press, bulk chemical feed storage, and all large tanks are outdoors. A single-story building required to house the equipment may be on the order of 50' x 100' with 20' clear headroom. A second floor addition will be required if the filter press is to be located indoors.

3.1.5 Estimated Capital Cost

The capital cost based on the preliminary sizing described above is an engineering estimation. The accuracy of the estimate is on the order of ±30%, which is typical for such estimation. These cost estimates have been compared with vendor cost estimates and are within the range of estimates provided by equipment vendors.

Component	Equipment Cost, $	Construction Cost, $	Total, $
Blowdown Storage	1,000,000	Included	1,000,000
Cooling Tower Blowdown & Pretreatment	4,500,000	4,500,000	9,000,000
Brine Crystallizer & Solids Handling	1,500,000	1,500,000	3,000,000
Building @$40/sf	200,000	Included	200,000
Subtotal	7,200,000	6,000,000	13,200,000
Construction Indirects @ 17%	1,224,000	1,020,000	2,244,000
Contingency @10%	720,000	600,000	1,320,000
Total	9,144,000	7,620,000	16,764,000

4.0 Discussion of the Definitions of Fresh Water and Brackish Water

The purpose of this section of the Technical Memorandum is to properly define both fresh water and brackish water. By establishing a correct definition for each term, a proper distinction can be generated between each water source. This clarification is intended to aid in the justification to allow the PEC the use of water from the lower confined aquifer for its cooling tower.

4.1 Fresh Inland Water

Inland fresh water is generally identified as water that contains low concentrations of dissolved salts and TDS. It is commonly identified as water that contains less than 0.5 parts per thousand, or 500 ppm, of dissolved salts. The California Environmental Protection Agency (EPA) State Water Resources Control Board (SWRCB) generally defines fresh water as water that is free of excessive salinity concentration, as per applicable California salinity thresholds(1). Fresh inland waters are further defined by the SWRCB through Resolution Number 75-58 as those inland waters that are suitable for use as sources of domestic, municipal, or agricultural water supply and which provide habitat for fish and wildlife.

(1) Applicable California salinity threshold can be found within the California Toxics Rule or in Basin Plans.

4.2 Brackish Water

Brackish water is generally identified as water with higher salinity and TDS concentrations than are found in fresh water, but lower concentrations than those found for sea water(2). Brackish water sources are usually formed from either the mixing of sea water with fresh water or from deposits found within brackish fossil aquifers. Generally, brackish water contains anywhere between 0.5 and 30 parts per thousand (500 – 30,000 ppm) of dissolved salts. The EPA SWRCB generally defines brackish water as a mixture of fresh water and salt water. The SWRCB defines brackish waters more specifically through Resolution Number 75-58 as all waters with a salinity range of 1,000 mg/L to 30,000 mg/L and a chloride concentration range of 250 mg/L to 12,000 mg/L.

4.3 Comparison to PEC Water Sources

Based on the aforementioned definitions for brackish water and fresh water, both the water found within the upper semi-confined aquifer and the lower confined aquifer can be classified as brackish water. Neither one of these water sources can be considered suitable for use as domestic, municipal, or agricultural water (without significant pretreatment being performed to it). In addition, water found within both of these aquifers has a TDS concentration greater or around 1,000 ppm, which classifies it more as brackish water than fresh water. Therefore, the PEC's use of either the confined or semi-confined aquifer as a water source for its operations should be considered permissible by the California Water Code and the SWRCB, since both sources are brackish water.

5.0 Conclusions

Based on the results of the comprehensive evaluations of source water and wastewater disposal options conducted in the *August 2006 AFC*, the *March 2, 2006 Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives*, and this *March 19, 2006 Supplemental Discussion of Water Supply and Wastewater Discharge Alternatives*, it is clear that the use of water from the confined aquifer for source water and the use of Deep Well Injections for wastewater disposal (Option B in this memorandum) is the best alternative based on economic feasibility, project performance, and environmental consequences. Further, based upon the classification of fresh and brackish water from EPA, Option B clearly adheres to all regulatory requirements. Therefore, the selection of using confined aquifer water and Deep Well Injection presents the best option for the PEC project.

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Technical Memorandum
Panoche Energy Center (PEC)

Water Quality Evaluation
April 24, 2007

Introduction

In earlier technical memorandums on the subject of water use for the proposed Panoche Energy Center (PEC) project, it was presented that the groundwater from confined aquifers would be the most appropriate water supply source for the project. This technical memorandum has been developed in response to questions raised in previous technical memorandums and to address the comments and questions generated by California Energy Commission (CEC) staff. The questions relate to whether the water from confined aquifers below the Corcoran Clay should be considered *inland waters that are suitable for use as sources of domestic, municipal, or agricultural water supply* and whether *it could be considered fresh inland waters.* These issues could raise questions regarding PEC's conformance with SWRCB Policy 75-58.

Degraded Water Quality

Degraded groundwater within the lower confined aquifers was selected to meet the PEC process water needs based on a comprehensive review of available sources of water supply and a decision analysis as described in the Application for Certification (AFC), where all potential available water sources were considered. The water in confined aquifers below the Corcoran Clay is considered to be a degraded water supply in accordance with the CEC definition of degraded water *as surface water, groundwater, treated municipal effluent or industrial process water which is not suitable for potable use because of natural or manmade contamination.* Degraded water includes *naturally occurring brackish water deemed too salty for human consumption or irrigation* (CEC, 2003[a])

Water for Domestic or Municipal Use
It is our opinion that the potential source of water for the PEC project complies with CEC policy. Because of the degraded nature of the water under consideration, there is minimum competition for an alternative use of the proposed water as there are no known domestic or municipal uses of groundwater within several miles of the PEC.

Groundwater is not typically considered a source of drinking water locally due to high specific conductance, sulfate, and total dissolved solids (TDS) as well as elevated levels of other parameters and constituents.

[a] California Energy Commission. 2003. Use of Degraded Water Sources as Cooling Water in Power Plants, P500-03-110.

- The water in the confined aquifer below Corcoran Clay contains high turbidity levels which are 10 to 50 times over the state and federal secondary limitations.
- The concentrations of some of the metal ions also exceed both state and federal secondary maximum contaminant levels (MCLs).
- High concentrations of boron are present in the local groundwater. Boron has been identified to have adverse effect on human health and is listed as a contaminant candidate by the U.S. Environmental Protection Agency (US EPA), although it is not regulated by the current drinking water standards due to its low natural occurrence. The boron health reference level has been calculated by US EPA at 1.4 milligrams per liter (mg/L) (US EPA, 2006[b]) whereas water samples from the confined aquifer indicate a boron concentration range from 1.6 to 3.0 mg/L.

The table below lists the parameters and constituents in the confined aquifer that exceed the MCLs set by the California Department of Health Service and US EPA.

Parameters	PEC Area Confined Aquifer Water Quality Data	California Department of Health Services[1]		U.S. Environmental Protection Agency	
		Primary MCL	Secondary MCL	Primary MCL	Secondary MCL
Specific Conductance	1,100-1,500 µS/cm		900 µS/cm		
Sulfate as SO4	370-440 ppm		250 ppm	500 ppm	250 ppm
TDS	820-1,100 ppm		500 ppm		500 ppm
Turbidity	45-260 NTU		5 NTU		
Manganese	0.026-0.36 ppm		0.05 ppm		0.05 ppm
Iron	0.14-45 ppm		0.3 ppm		0.3 ppm

µS/cm = microsiemens per centimeter

ppm = parts per million (equivalent to mg/L)

[1] Title 22 California Code of Regulations

Water for Irrigation Use

While groundwater has been used for irrigation of land surrounding the PEC in the past, it has been replaced by higher quality surface water under normal conditions. Past usage of the groundwater for irrigation was generally limited to more salt tolerant crops (e.g., cotton and grain) than those prevalent in the surrounding area today. Information presented in Section 5.5.1.7.1 of the AFC describes the following changes in local irrigation practices:

> *Early farmers in the Westlands Sub-basin made use of groundwater for irrigation. In 1968, the delivery of surface water with low levels of dissolved solids from the San Luis Unit of the federal Central Valley Project (CVP) largely replaced the use of groundwater containing elevated levels of dissolved solids for irrigation. However, in response to drought conditions and other surface water shortfalls beginning in 1988, farmers reactivated old wells and constructed new wells in order to pump groundwater to irrigate their crops.*

[b] U.S. Environmental Protection Agency Office of Water, 2006. Health Effects Support Document for Boron.

> *Surface water delivered by the Westlands Water District is generally used rather than groundwater wells, and many wells in the area have collapsed or are abandoned.*

A few functional irrigation wells are still present within the surrounding area but are rarely used because the groundwater they produce is not suitable for irrigation of most of the crops that are presently grown in the area and can be damaging to the soil. Farmers in the area typically purchase surface water from the Westlands water district at a higher cost than pumping groundwater underlying their property. Acceptance of this cost penalty indicates that the local farmers consider usage of groundwater as the sole source of irrigation water to be undesirable.

Typically, the following basic criteria are used to evaluate water quality for irrigation purposes (Follett and Soltanpour, 1999[c]):

- Total soluble salt content (salinity hazard)
- Relative proportion of sodium cations to other cations (sodium hazard)
- Excessive concentration of toxic elements (e.g., chloride, boron)
- Bicarbonate anion concentrations related to calcium and magnesium cations

Groundwater within the confined aquifers underlying the site presents threats to crops and soils including salinity, sodium, and boron hazards. The effect of the hazard of water quality on irrigation by individual properties is presented in an attachment to this memorandum.

Conclusion

The information presented though this memorandum clearly demonstrates that the competitive uses of the water supply selected for PEC are insignificant. Groundwater supplies within the confined aquifers underlying the site are not known to be used for domestic or municipal supply in the surrounding area and may only be used for agricultural supply on a short-term basis if surface water is unavailable. The groundwater presents a high sodium hazard and is generally unsuitable for continuous use as a sole source water supply. In addition, the groundwater is unsuitable for irrigation of crops sensitive to boron and usage on crops semi-tolerant to boron ranges from permissible to unsuitable depending on the crop. High sulfate concentrations in the groundwater also present a hazard of foliar leaf burn when sprinklers are used for irrigation. It is not beneficial to use groundwater within the confined aquifers for either domestic and municipal supply purposes or agricultural irrigation purposes. Based on these usage limitations, it appears that groundwater meets the degraded water criteria presented through the "Use of Degraded Water Sources As Cooling Water in Power Plants" CEC Consultant Report (CEC, 2003) guidance, and is therefore an appropriate water supply for the PEC project.

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[c] Follett, R.H., and P.N. Soltanpour. 1999. Irrigation Water Quality Criteria, Colorado State University Cooperative Extension.

Attachment: Hazardous Effect of Water Quality on Agricultural Irrigation Uses

Typically, the following basic criteria are used to evaluate water quality for irrigation purposes (Follett and Soltanpour, 1999):

- Total soluble salt content (salinity hazard)
- Relative proportion of sodium cations to other cations (sodium hazard)
- Excessive concentration of toxic elements (e.g., chloride, boron)
- Bicarbonate anion concentrations related to calcium and magnesium cations

The following evaluation evaluates irrigation water quality hazards presented by groundwater within the confined aquifers based on recent sampling of monitoring wells at the Panoche Energy Center (PEC). Groundwater data for these samples are summarized on Tables 1 and 2.

Salinity Hazard

Excess salt increases the osmotic pressure in the soil that can result in a physiological drought condition. While the soil can appear to contain sufficient moisture for the crop, plants will wilt because their roots cannot absorb enough water to replace that lost by transpiration. The total soluble salt content of irrigation water is generally measured by determining its electrical conductivity (EC) or by determining the actual salt content [measured as total dissolved solids (TDS)] (Follett and Soltanpour, 1999). Based on recent sampling of monitoring wells at the PEC, the EC in confined aquifer groundwater underlying the site ranges from about 1,100 to 1,500 microsiemens per centimeter ($\mu S/cm$) and the TDS range from about 820 to 1,100 milligrams per liter (mg/L). Usage of irrigation water within this range is permissible from an agricultural standpoint if leaching for salinity management is practiced. This technique requires excess water to be applied keep the salts in solution and flush them below the root zone (Fipps, 2003).

Sodium Hazard

The sodium hazard of irrigation water usually is expressed as the sodium adsorption ratio (SAR). This is the proportion of sodium to calcium plus magnesium as milliequivalents per liter in the water ($SAR = Na/(Ca+Mg/2)^{1/2}$). Sodium contributes directly to the total salinity and may be toxic to sensitive crops such as fruit trees and grapes, but the main problem with a high sodium concentration is its effect on the physical properties of soil. Continued use of high SAR value water leads to a breakdown in the physical structure of the soil caused by excessive amounts of colloidally absorbed sodium and results in the dispersion of soil clay that causes the soil to become hard and compact when dry and increasingly impervious to water penetration due to dispersion and swelling when wet. Use of water with a SAR value greater than 10 should be avoided if it will be the only source of irrigation water for long periods even if the total salt content is relatively low (Follett and Soltanpour, 1999). Based on recent sampling of monitoring wells at the PEC, the SAR of confined aquifer groundwater ranges from about 18 to 20. The sodium hazard of this water is considered high from an agricultural standpoint, and the water is generally unsuitable for continuous use (Fipps, 2003).

Toxic Elements

Direct toxicity to crops may result from chemical elements in irrigation water. The concentration of an element in water that will cause toxic symptoms varies depending on the crop. There is a long list of elements that can cause a toxic effect on crops. After sodium, chloride and boron are of most concern. Based on recent sampling of monitoring wells at the PEC, the chloride concentrations in the confined aquifer groundwater range from about 40 to 85 mg/L. These concentrations are not likely to cause a loss in crop yield. Boron concentrations, however, ranged from about 1.6 to 3.0 mg/L. These concentrations are satisfactory only for semi-tolerant to tolerant crops (Follett and Soltanpour, 1999). While a necessary nutrient, high boron levels cause plant toxicity ranging from acute to chronic and can accumulate in the soil. Boron sensitivity of local crops ranges from sensitive (e.g., almonds, stone fruits, and grapes) to semi-tolerant (e.g., tomato) (Fipps, 2003). Local farmers reportedly do not blend groundwater with surface water for irrigation due to high boron concentrations in the groundwater that make it unsuitable for agricultural use on the crops planted in the area.

Bicarbonate Concentration

Waters high in bicarbonate tend to precipitate calcium carbonate and magnesium carbonate due to evapotranspiration. This increases the proportion of sodium ions and increases the sodium hazard of the water to a level greater than that indicated by the SAR value (Follett and Soltanpour, 1999). Concentrations of bicarbonate in confined aquifer groundwater range from about 61 to 200 mg/L based on recent sampling of monitoring wells at the PEC. The sodium adsorption ratio can be adjusted for high bicarbonate concentrations (Fipps, 2003) but that does not appear to be warranted for groundwater in the confined aquifers underlying the PEC.

Sulfate Hazard

In addition to the most of the basic criteria described previously, sulfate presents a hazard to crops irrigated using groundwater from the confined aquifers. Sulfate concentrations exceeding approximately 200 mg/L can cause foliar leaf burn when using sprinkler irrigation. Concentrations of sulfate in the confined aquifer groundwater ranged from about 370 to 440 mg/L based on recent sampling of monitoring wells at the PEC.

References

California Energy Commission. 2003. Use of Degraded Water Sources as Cooling Water in Power Plants, P500-03-110.

Fipps, G. 2003. Irrigation Water Quality Standards and Salinity Management Strategies, Texas Cooperative Extension, Texas A&M University.

Follett, R.H., and P.N. Soltanpour. 1999. Irrigation Water Quality Criteria, Colorado State University Cooperative Extension.

TABLE 1
INORGANICS CONCENTRATIONS IN WATER
Panoche Energy Center
Fresno County, California

Well Identification		Lower Confined Aquifer MW-1				Upper Confined Aquifer MW-2				Semi-Confined Aquifer			Water Quality Limits For Constituents[a]					
													CDHS[b]		USEPA[c]			
Sample Identification		MW-1	MW-4 (Blind Duplicate of MW-1)	MW-1		MW-2	MW-5 (Blind Duplicate of MW-2)	MW-2		MW-3			Primary MCL[d]	Secondary MCL[e]	Primary MCL	Secondary MCL	CA PHG[f]	Ag Water Quality Limits[g]
		Sample Date																
Constituent or Parameter	Units	10/25/2006	10/25/2006	2/16/2007	4/11/2007	10/25/2006	10/25/2006	2/16/2007	4/11/2007	10/27/2006	2/16/2007	4/11/2007						
Total Alkalinity as $CaCO_3$	mg/L[h]	180	180	180	170	110	110	100	50	180	170	--[p]	-	-	-	-	-	-
Bicarbonate Alkalinity as HCO_3	mg/L	200	200	200	190	130	140	120	61	230	210	--[p]	-	-	-	-	-	-
Carbonate Alkalinity as CO_3	mg/L	< 20	< 20	<20	<20	< 20	< 20	<20	<20	< 20	<20	--[p]						
Hydroxide Alkalinity as OH	mg/L	< 20	< 20	<20	<20	< 20	< 20	<20	<20	< 20	<20	--[p]						
Ammonia as N	mg/L	< 1.0	< 1.0	<1.0	<1.0	< 1.0	< 1.0	<1.0	<1.0	< 1.0	<1.0	<1.0						
Biochemical Oxygen Demand	mg/L	< 1.0	< 1.0	1.5	1.3	< 1.0	< 1.0	<1.0	1.4	< 1.0	<1.0	<1.0						
Chloride	mg/L	85	85	73	66	40	41	42	41	**160**	**160**	**160**	-	250	-	250	-	106
Chemical Oxygen Demand	mg/L	< 10	< 10	24	40	26	< 10	16	27	< 10	11	22	-	-	-	-	-	-
Cyanide (total)	mg/L	< 0.005	< 0.005	<0.0050	<0.0050	< 0.005	< 0.005	<0.0050	<0.0050	< 0.005	<0.0050	<0.0050						
Specific Conductance (EC)	µS/cm[i]	**1,500**	**1,500**	**1,500**	**1,400**	**1,100**	**1,100**	**1,200**	**1,200**	**3,000**	**3,200**	**3,200**		900			-	700
Fluoride	mg/L	0.60	0.68	0.44	0.61	0.56	0.59	0.35	0.73	0.71	0.50	<2.5	2		4	2	1	1
Hardness	mg equiv. $CaCO_3$/L[j]	40	41	48	34	56	56	42	44	1,100	1,200	1,100	-	-	-	-	-	-
Methylene Blue Active Substances	mg/L	< 0.050	< 0.050	<0.050	<0.050	< 0.050	< 0.050	<0.050	<0.050	< 0.050	<0.050	<0.050						
Nitrate as NO_3	mg/L	< 6.0	< 6.0	<2.0	<10	< 6.0	< 6.0	<2.0	<10	**27**	**31**	<50	45	-	10	-	10	-
Orthophosphate as P	mg/L	< 1.5	< 1.5	<0.50	<2.5	< 1.5	< 1.5	<0.50	<2.5	< 1.5	<0.50	<12						
pH	pH units	**8.9**	**9.0**	**8.7**	**9.0**	**8.6**	**8.6**	**8.5**	8.4	8.1	8.0	8.1				6.5 - 8.5		6.5 - 8.4
Phosphorus	mg/L	0.12	0.16	0.15	<0.10	0.14	< 0.10	0.11	<0.10	< 0.10	<0.10	<0.10	-	-	-	-	-	-
Sulfate as SO_4	mg/L	**440**	**440**	**410**	**430**	**380**	**400**	**370**	**410**	**1,500**	**1,500**	**1,700**	-	250	500	250	-	-
Sulfide	mg/L	< 1.0[k]	< 1.0[k]	--[o]	<1.0	< 1.0[k]	< 1.0[k]	--[o]	<1.0	< 1.0	--[o]	<1.0						
Total Dissolved Solids	mg/L	**1,100**	**1,100**	**1,000**	**1,000**	**840**	**840**	**850**	**820**	**2,900**	**2,900**	**2,900**	-	500	-	500	-	450
Total Organic Carbon	mg/L	1	< 1.0	1.0	1.3	< 1.0	1	<1.0	1.9	< 1.0	<1.0	<1.0	-	-	-	-	-	-
Total Suspended Solids	mg/L	110	94	76	< 40[n]	25	15	<40	< 40[n]	< 4.0	<10	< 40[n]	-	-	-	-	-	-
Turbidity	NTU[l]	**89[m]**	**87[m]**	**200**	**260**	**52[m]**	**45[m]**	**180**	**72**	**2.3**	**19**	**7.4**	1 or 5	5	1 or 5	-	-	-

Note: Values shown in bold print exceed one or more water quality limits shown on right.
[a] Water quality limits for detected constituents summarized from A Compilation of Water Quality Goals, August, 2003, Regional Water Quality Control Board, Central Valley Region
[b] California Department of Health Services
[c] U.S. Environmental Protection Agency
[d] Primary Maximum Contaminant Level
[e] Secondary Maximum Contaminant Level
[f] California Office of Environmental Health Hazard Assessment Public Health Goal in Drinking Water
[g] Agricultural Water Quality Limits based on Ayers, R.S. and D.W. Westcot, Water Quality for Agriculture, Food and Agriculture Organization of the United Nations - Irrigation and Drainage Paper No. 29, Rev. 1, Rome, 1965, as summarized in A Compilation of Water Quality Goals, August, 2003

[h] mg/L = milligrams per liter
[i] µS/cm = microsiemens per centimeter
[j] mg equiv. $CaCO_3$/L = milligrams equivlent calcium carbonate
[k] Analyst noted that samples were orange in color and indicated possible matrix interference
[l] NTU = Nephelometric Turbidity Units
[m] Sample analyzed outside of U.S. Environmental Protection Agency recommended holding time
[n] Sample analyzed at a dilution due to limited sample volume
[o] Sample not collected - no sample container provided by laboratory
[p] Sample not analyzed due to inadequate sample volume

Well Identification		Lower Confine			Water Quality Limits For Constituents[a]			
		MW-1			USEPA[c]			
Sample Identification		MW-1	MW-4 (Blind Duplicate of MW-1)	ry	Primary MCL	Secondary MCL	CA PHG[f]	Ag Water Quality Limits[g]
Constituent	Units	10/25/2006	10/25/2006					
Aluminum	mg/L[h]	< 0.050	< 0.050					
Antimony	mg/L	< 0.0050	< 0.0050					
Arsenic	mg/L	< 0.010	< 0.010					
Barium	mg/L	0.19	0.18		2		0.7	
Beryllium	mg/L	< 0.0010	< 0.0010					
Boron	mg/L	**2.9**	**3.0**		-	-	-	0.7 or 0.75
Cadmium	mg/L	< 0.0010	< 0.0010					
Calcium	mg/L	11	11		-	-	-	-
Chromium	mg/L	< 0.0050	< 0.0050					
Cobalt	mg/L	< 0.0020	< 0.0020					
Copper	mg/L	< 0.0050	< 0.0050					
Iron	mg/L	**5.9**	**5.8**		-	0.3	-	5
Lead	mg/L	< 0.0050	< 0.0050					
Magnesium	mg/L	3.1	3.2		-	-	-	-
Manganese	mg/L	**0.12**	**0.12**		-	0.05	-	2
Mercury	mg/L	< 0.0002	< 0.0002					
Molybdenum	mg/L	**0.04**	**0.041**		-	-	-	0.01
Nickel	mg/L	< 0.0050	< 0.0050					
Potassium	mg/L	4.7	4.9		-	-	-	-
Selenium	mg/L	< 0.020	< 0.020		0.05	-	-	0.02
Silica (SiO2)	mg/L	31	32		-	-	-	-
Silicon	mg/L	14	15		-	-	-	-
Silver	mg/L	< 0.0050	< 0.0050					
Sodium	mg/L	**300**	**310**		-	-	-	69
Strontium	mg/L	0.114	0.118		-	-	-	-
Thallium	mg/L	< 0.020	< 0.020					
Tin	mg/L	< 0.010	< 0.010					
Titanium	mg/L	< 0.010	< 0.010					
Vanadium	mg/L	< 0.010	< 0.010					
Zinc	mg/L	0.015	0.017			5		2

Note: Values shown in bold print exceed one or more water quality l

[a] Water quality limits for detected constituents summarized from A C

[b] California Department of Health Services

[c] U.S. Environmental Protection Agency

[d] Primary Maximum Contaminant Level

[e] Secondary Maximum Contaminant Level

[f] California Office of Environmental Health Hazard Assessment Pub

[g] Agricultural Water Quality Limits from Ayers, R.S. and D.W. Westn A Compilation of Water Quality Goals, August, 2003

[h] mg/L = milligrams per liter

Panoche Energy Center, LLC

July 27, 2007

James W. Reede, Jr., Ed.D
Energy Facility Siting Project Manager
California Energy Commission
1516 9th Street
Sacramento, CA 95814

Re: Panoche Water Supply Alternatives

Dear Dr. Reede:

Panoche Energy Center, LLC ("Panoche") has previously provided to CEC staff via several technical memorandums[1] a discussion of the environmental and economic impacts of using (1) wastewater effluent from the City of Mendota and (2) using semi-confined aquifer water for process water. The economic impacts as discussed in those memos and herein are of such magnitude that if the Panoche project is required to incur such costs, the project will be cancelled. In addition to the environmental and economic considerations, the two alternatives are not practical from either a schedule or technical standpoint.

Economic Impact

After Tuesday's workshop, we requested that Bibb and Associates prepare a refined and updated review of all additional costs associated with the CEC proposed alternatives. That information is summarized as follows:

Item	Cost Estimate
18 mile water pipeline to Mendota	$18 million capital cost
Softening system for semi-confined aquifer	$12 million capital cost
Additional injection well	$1.5 million capital cost
Larger RO system to treat additional water	$6 million capital cost
Contracted EPC and TG cost	$263 million capital cost
% Increase in capital costs	14.3%
Additional O&M costs for Mendota water treatment (Title 22)	Unknown
Additional O&M costs for softening	$2.14 million annually
Additional O&M costs for larger RO system	Unknown
Current projected annual O&M costs	$16.6 million annually
% Increase in annual O&M costs	>12.9%

[1] The following technical memos have been provided by Panoche to CEC staff:
March 2, 2007 – Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives
March 23, 2007 – Supplemental Discussion of Water Supply and Wastewater Discharge Alternatives
April 24, 2007 – Water Quality Evaluation
July 20, 2007 – Response to "Alternative Water Supply" and "Dry Cooling"

Since the wastewater effluent from Mendota is insufficient to supply the needs of Panoche, Panoche would be required to acquire additional supply water from the semi-confined aquifer as proposed by CEC staff. In addition to the cost to use Mendota water and semi-confined aquifer water, there are significant schedule and project uncertainty issues as described below. The economic impacts have to take into account the combined effect of both alternatives.

Practical and schedule impacts of using Mendota wastewater effluent:

1. Effluent from Mendota cannot provide even half of the amount of water that is required when running at continuous full load.
2. Panoche's water demand will be on an hourly basis (not daily or annually) with the maximum demand expected to occur frequently during hot periods but potentially for short periods of time. Much (if not most) of the time Panoche will not be able to take effluent from Mendota as Panoche will not be running.
3. Operations of Panoche cannot be subject to wastewater availability from Mendota at any moment in time or long term.
4. Constructing a water line would require a crossing of the Southern Pacific railroad track which typically requires a minimum of two years to obtain approval from the railroad.
5. Constructing a water line would require crossing of the California aqueduct.
6. It is not possible to determine or analyze at this time other technical, schedule, or environmental impacts related to route selection, environmental surveys, right-of-way acquisition, and other unknown impacts.

Practical and schedule impacts for using semi-confined aquifer water:

1. This water would have to be softened for cooling tower use (not required for confined aquifer water) and would result in RO treatment of more than three times as much water.
2. Lime and soda ash softening systems are designed for continuous operation and are incompatible with a peaking plant that will require frequent and fast start-up.
3. Five additional people would be required to operate the softening system on a continuous basis.
4. RO reject would increase overall raw water consumption by 11%.
5. The wastewater injection amount would increase by 44% thus requiring at least one additional injection well and associated capital and operating costs.
6. Plant layout would have to be redesigned and additional land acquired for water treatment resulting in significant schedule delays, additional environmental impacts and Williamson Act cancellation.
7. The additional RO equipment will increase auxiliary power usage by an estimated 600 kW significantly impacting Panoche's ability to meet its contracted delivery amount.

Project Schedule

Changes to the Panoche water plan as proposed by staff will result in significant delays due to additional land acquisition and consequent environmental review, revised air modeling and permitting due to revised plant layout and lime and soda ash dust, cancellation of additional land under the Williamson Act, and additional biological mitigation.

1. The above revisions would require many months to complete.
2. Panoche has entered into a fixed price EPC contract that requires Notice to Proceed 18 months prior to the in-service date. Beginning on February 1, 2008 the fixed EPC contract price escalates at $51,200 per day in addition to day for day extension of the in-service date. After February 15, 2008 the fixed price is subject to renegotiation and the contract subject to cancellation.
3. The PPA required in-service date is August 1, 2009.
4. Panoche cannot sustain any more delays in schedule and meet its required in-service date.

Confined Water Mitigation Plan
Panoche has previously over a several month period discussed a water enhancement or mitigation program with CEC staff with various vague responses from staff. Specifically, Panoche has been working with Westlands Water District to provide a one time contribution for its loan program to farmers for installation of water conservation measures including drip irrigations systems, aluminum piping, etc. Westlands has expressed a strong interest to enter into an agreement for such contribution. Panoche is willing to enter into a contribution program that would provide a 1 for 1 offset of water used by Panoche from the confined aquifer based on the following conditions:

1. Estimated acre feet of water saved per year per $500,000 loan – 209 acre feet (per Westlands)
2. Impact of contribution is compounded every four years as a result of repayment of loans and new loans made for additional conservation systems
3. Average life cycle of conservation systems installed is a minimum of 8 years (per Westlands)
4. Discount of the value of confined aquifer water at a ratio of 3 to 1 since it is approximately three times higher in TDS than surface water that it is conserving
5. Panoche water usage is actually expected to be much less on an annual basis due to anticipated operations of much less than 5000 hours per year, however the model uses 5000 hours for comparison purposes
6. Based on these assumptions the water savings over the 20 year life plus the construction period of Panoche exceeds the maximum water usage
7. The draft Memorandum of Understanding that we provided to Westlands Water District is attached along with a spreadsheet reflecting the long term water savings from the mitigation plan is attached.

Summary
Panoche Energy Center, LLC has extensively reviewed the water supply alternatives proposed by CEC staff with its engineering firm and environmental consultants and has concluded that such alternatives are impractical, environmentally undesirable and economically unsound. The enormous cost impacts and schedule delays occasioned by staff's proposal will result in cancellation of the Panoche Energy Center project. To date Panoche has incurred costs in excess of $16 million for the development, permitting, and design of the project and continues to incur expenses and liabilities at a cost that is now approximately $4 million per month. We are prepared to go forward with our proposed water mitigation program and request that staff come to next week's workshop prepared to reach agreement at that time on the specific details of the proposed mitigation plan so that it can be presented to the Westlands board at its August meeting and so that the FSA will not be further delayed.

Very truly yours,

Gary R. Chandler
President
Panoche Energy Center, LLC

Attachments

Cc: Eileen Allen
Roger Johnson
Richard Anderson
Service List

MEMORANDUM OF UNDERSTANDING

This MEMORANDUM OF UNDERSTANDING (the "Memorandum") is entered into as of August __, 2007 by and between Westlands Water District ("Westlands") and Panoche Energy Center, LLC, a Delaware limited liability company ("PEC").

RECITALS

A. Westlands is a purveyor of water from the State Water Project to farmers in Central California and offers an Expanded Irrigation System Improvement Program (EISIP) which provides low interest loans to water users and landowners for the lease-purchase of irrigation system equipment. The EISIP allows for the design of irrigation systems and purchase of portable aluminum irrigation pipe, micro-irrigation, linear move, center pivots, and tail-water reuse systems.

B. Panoche has entered into a power purchase agreement with Pacific Gas & Electric Company for delivery of capacity and energy of up to 400MW up to 5000 hours per year for a 20 year period beginning in August 2009.

C. Panoche is in the process of permitting the 400MW peaking facility through the California Energy Commission with final approval expected in late 2007 or early 2008 and financial closing in early 2008.

D. The Panoche project will be constructed on 12.8 acres of land adjacent to the PG&E Panoche substation located in west Fresno County approximately 2 miles east of I-5 on West Panoche Road.

E. As an enhancement to its proposed water usage and discharge plan, Panoche proposes to make a contribution to Westlands for water conservation.

The following are the parties understanding with respect to the proposed contribution from Panoche to Westlands.

1. Contribution to Westlands. Panoche will make a one-time contribution to Westlands in the amount of $500,000 (the "Contribution") to be used at Westlands discretion for water conservation programs as generally described above in Recital A and under its sponsorship. The Contribution is contingent on final licensing of Panoche by the California Energy Commission and financial closing. The Contribution will be made by check or wire transfer upon such final approval of licensing of Panoche by the California Energy Commission and financial closing.

2. Conservation Amount. Panoche and Westlands acknowledge that the water conservation estimate of 209 acre feet per year for the Contribution is based on water use savings predicted by Westlands from its farmer loan program with the loans repaid every four years and the payments then used for new loans. This has a compounding affect on water savings over time. The estimated water use savings is

209 acre feet per year compounding every four years. Westlands estimates that the average life of installed conservations systems is approximately 8 years or greater.

3. Reporting Requirements. Westlands will provide reasonable data and information regarding use of Contribution and estimated water use savings as may be requested from time to time by Panoche and the California Energy Commission.

4. Other Conditions. The Contribution will not be refunded or returned to Panoche. There are no other conditions associated with the proposed agreement.

Whereupon the parties have executed this Memorandum of Understanding as of August __, 2007:

Westlands Water District	Panoche Energy Center, LLC, a Delaware limited liability company
By:______________________	By:______________________
Name:____________________	Name:____________________
Title:____________________	Title:____________________

209 AF / Year, $500K Contribution Water Savings

Year (Life of PEC Project)	Annual Water Use by PEC (AF/Y)	Annual H20 Savings with Improved Irrigation System (AF/Y)
1	1135	209
2	1135	209
3	1135	209
4	1135	209
5	1135	418
6	1135	418
7	1135	418
8	1135	418
9	1135	627
10	1135	627
11	1135	627
12	1135	627
13	1135	836
14	1135	836
15	1135	836
16	1135	836
17	1135	1045
18	1135	1045
19	1135	1045
20	1135	1045
21		1254
21.5		627
22		1254
23		1254
24		1254
25		1463
26		1463
27		1463
28		1463
29		1672
30		1672
TOTAL PEC Water Use (AF)	**22700**	
TOTAL Water Savings After 21.5 Years (AF)		**13794**
TOTAL Water Savings After 30 Years (AF)		**27379**
TOTAL Additional H20 Savings Exceeding PEC Water Use After 30 Years (AF)		**4679**

Assumptions
1.) Assumed Furrow Irrigation Efficiency = 0.75
2.) Assumed Drip/Micro Irrigation Efficiency = 0.82
3.) Average Crop Evapotranspiration = 3 feet/Yr.
4.) Water Savings = 0.34 feet
5.) Acres Per System = 160 Acres
6.) Amount Loaned/System = $130,000
7.) Repayment Period = 4 Years

Based on assumptions listed above,
Yield = $500,000 / $130,000 x 160 acres x 0.34 feet
Yield = 209 AF/ year

Source: Russ Freeman, Supervisor of Resources, Westlands Water District, Fresno, CA. June 2007

Conclusion
Assuming a water savings of 209 AF / year, after 28 years the water savings would be equivalent to the water use by the PEC based on a contribution of $500,000 to the Irrigation System Improvement Program After 21.5 years, total water savings would be 13.794 AF.

Additional water savings in excess PEC water use

Panoche Water Mitigation Plan

Year (Life of PEC Project)	Average Annual Water Use Based on 5000 Hours of Operation (AF/Y)	Cumlative Water Usage (AF/Y)	Annual Water Savings From Mitigation Plan (AF/Y)	Cumlative Water Savings (AF/Y)
Construction			314	314
Construction			627	941
1	1,135	1,135	627	1,568
2	1,135	2,270	627	2,195
3	1,135	3,405	941	3,135
4	1,135	4,540	1,254	4,389
5	1,135	5,675	1,254	5,643
6	1,135	6,810	1,254	6,897
7	1,135	7,945	1,254	8,151
8	1,135	9,080	1,254	9,405
9	1,135	10,215	1,254	10,659
10	1,135	11,350	1,254	11,913
11	1,135	12,485	1,254	13,167
12	1,135	13,620	1,254	14,421
13	1,135	14,755	1,254	15,675
14	1,135	15,890	1,254	16,929
15	1,135	17,025	1,254	18,183
16	1,135	18,160	1,254	19,437
17	1,135	19,295	1,254	20,691
18	1,135	20,430	1,254	21,945
19	1,135	21,565	1,254	23,199
20	1,135	22,700	1,254	24,453
21			1,254	25,707
22			1,254	26,961
23			1,254	28,215
24			1,254	29,469
25			1,254	30,723
26			1,254	31,977
27			1,254	33,231
28			1,254	34,485
29			1,254	35,739
30			1,254	36,993

Assumptions
1) Assumed Furrow Irrigation Efficiency = 0.75
2) Assumed Drip/Micro Irrigation Efficiency = 0.82
3) Average Annual Crop Evapotranspiration = 3.0 feet/Ac
4) Water Savings = 0.34 feet
5) Acres Per System = 160 Acres
6) Amount Loaned/System = $130,000
7) Repayment period = 4 Years
8) Average system life = 8 Years

Based on assumptions listed above,
Yield = $500,000 / $130,000 x 160 acres x 0.34 feet
Yield = 209 AF/year * 3 = 627 AF/year (see Notes below)

Source: Russ Freeman, Supervisor of Resources, Westlands Water District, Fresno, CA. June 2007

Notes:
1) Value of Panoche water is discounted by two-thirds due to three times higher TDS concentration
2) Expected water usage will be considerably lower due to operating less than 5000 hours per year
3) Value for mitigation contribution will continue in perpetuity

WATER QUALITY CONTROL POLICY

on the

USE and DISPOSAL of INLAND WATERS

USED for POWERPLANT COOLING

ADOPTED JUNE 19, 1975

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CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

STATE WATER RESOURCES CONTROL BOARD
RESOLUTION NO. 75-58

WATER QUALITY CONTROL POLICY ON THE USE AND DISPOSAL OF INLAND WATERS USED FOR POWERPLANT COOLING

WHEREAS:

1. Basin Planning conducted by the State Board has shown that there is presently no available water for new allocations in some basins.

2. Projected future water demands, when compared to existing developed water supplies, indicate that general freshwater shortages will occur in many areas of the State prior to the year 2000.

3. The improper disposal of powerplant cooling waters may have an adverse impact on the quality of inland surface and groundwaters.

4. It is believed that further development of water in the Central Valley will reduce the quantity of water available to meet Delta outflow requirements and protect Delta water quality standards.

THEREFORE, BE IT RESOLVED, that

1. The Board hereby adopts the "Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling".

2. The Board hereby directs all affected California Regional Water Quality Control Boards to implement the applicable provisions of the policy.

3. The Board hereby directs staff to coordinate closely with the State Energy Resources Conservation and Development Commission and other involved state and local agencies as this policy is implemented.

CERTIFICATION

The undersigned, Executive Officer of the State Water Resources Control Board, does hereby certify that the forgoing is a full, true, and correct copy of a resolution duly and regularly adopted at a meeting of the State Water Resources Control Board held on June 19, 1975.

Bill B. Dendy
Executive Officer

WATER QUALITY CONTROL POLICY ON THE USE AND DISPOSAL OF INLAND WATERS USED FOR POWERPLANT COOLING

Introduction

The purpose of this policy is to provide consistent statewide water quality principles and guidance for adoption of discharge requirements, and implementation actions for powerplants which depend upon inland waters for cooling. In addition, this policy should be particularly useful in guiding planning of new power generating facilities so as to protect beneficial uses of the State's water resources and to keep the consumptive use of freshwater for powerplant cooling to that minimally essential for the welfare of the citizens of the State.

This policy has been prepared to be consistent with federal, state, and local planning and regulatory statutes, the Warren-Alquist State Energy Resources Conservation and Development Act, Water Code Section 237 and the Waste Water Reuse Law of 1974.

Section 25216.3 of the Warren-Alquist Act states:

"(a) The commission shall compile relevant local, regional, state, and federal land use, public safety, environmental, and other standards to be met in designing, siting, and operating facilities in the State: except as provided in subdivision (d) of Section 25402, adopt standards, except for air and water quality,...."

Water Code Section 237 and Section 462 of the Waste Water Reuse Law, direct the Department of Water Resources to:

237. "...either independently or in cooperation with any person or any county, state, federal, or orhter agency, including, but not limited to, the State Energy Resources Conservation and Development Commission, shall conduct studies and investigations on the need and availability of water for thermal electric powerplant cooling purposes, and shall report thereon to the Legislature from time to time...."

462. "...conduct studies and investigations on the availability and quality of waste water and uses of reclaimed waste water for beneficial purposes including, but not limited to ... and cooling for thermal electric powerplants."

Decisions on waste discharge requirements, water rights permits, water quality control plans, and other specific water quality control implementing actions by the State and Regional Boards shall be consistent with provisions of this policy.

The Board declares its intent to determine from time to time the need for revising this policy.

Definitions

1. Inland Water – all waters within the territorial limits of California exclusive of the waters of the Pacific Ocean outside of enclosed bays, estuaries, and coastal lagoons.

2. Fresh Inland Waters – those inland waters which are suitable for use as a source of domestic, municipal, or agricultural water supply and which provide habitat for fish and wildlife.

3. Salt Sinks – areas designated by the Regional Water Quality Control Boards to receive saline waste discharges.

4. Brackish Waters – includes all waters with a salinity range of 1,000 to 30,000 mg/l and a chloride concentration range of 250 to 12,000 mg/l. The application of the term "brackish" to a water is not intended to imply that such water is no longer suitable for industrial or agricultural purposes.

5. Steam-Electric Power Generating Facilities – electric power generating facilities utilizing fossil or nuclear-type fuel or solar heating in conjunction with a thermal cycle employing the steam-water system as the thermodynamic medium and for the purposes of this policy is synonomous with the word "powerplant".

6. Blowdown – the minimum discharge of either boiler water or recirculating cooling water for the purpose of limiting the buildup of concentrations of materials in excess of desirable limits established by best engineering practice.

7. Closed Cycle Systems – a cooling water system from which there is no discharge of wastewater other than blowdown.

8. Once-Through Cooling – a cooling water system in which there is no recirculation of the cooling water after its initial use.

9. Evaporative Cooling Facilities – evaporative towers, cooling ponds, or cooling canals, which utilize evaporation as a means of wasting rejected heat to the atmosphere.

10. Thermal Plan – "Water Quality Control Plan for Control of Temperature In the Coastal and Interstate Waters and Enclosed Bays and Estuaries of California".

11. Ocean Plan – "Water Quality Control Plan for Ocean Waters of California".

<u>Basis of Policy</u>

1. The State Board believes it is essential that every reasonable effort be made to conserve energy supplies and reduce energy demands to minimize adverse effects on water supply and water quality and at the same time satisfy the State's energy requirements.

2. The increasing concern to limit changes to the coastal environment and the potential hazards of earthquake activity along the coast has led the electric utility industry to consider siting steam-electric generating plants inland as an alternative to proposed coastal locations.

3. Although many of the impacts of coastal powerplants on the marine environmental are still not well understood, it appears the coastal marine environment is less susceptible than inland waters to the water quality impacts associated with powerplant cooling. Operation of existing coastal powerplants indicate that these facilities either meet the standards of the State's Thermal Plan and Ocean Plan or could do so readily with appropriate technological modifications. Furthermore, coastal locations provide for application of a wide range of cooling technologies which do not require the consumptive use of inland waters and therefore would not place an additional burden on the State's limited supply of inland waters. These technologies include once-through cooling which is appropriate for most coastal sites, potential use of saltwater cooling towers, or use of brackish water where more stringent controls are required for environmental considerations at specific sites.

4. There is a limited supply of inland water resources in California. Basin planning conducted by the State Board has shown that there is no available water for new allocations in some basins. Projected future water demands when compared to existing developed water supplies indicate that general fresh-water shortages will occur in many areas of the State prior to the year 2000. The use of inland waters for powerplant cooling needs to be carefully evaluated to assure proper future allocation of inland waters considering all other beneficial uses. The loss of inland waters considering all other beneficial uses. The loss of inland waters through evaporation in powerplant cooling facilities may be considered an unreasonable use of inland waters when general shortages occur.

5. The Regional Boards have adopted water quality objectives including temperature objectives including temperature objectives for all surface waters in the State.

6. Disposal of once-through cooling waters from powerplants to inland water is incompatible with maintaining the water quality objectives of the State Board's "Thermal Plan" and "Water Quality Control Plans."

7. The improper disposal of blowdown from evaporative cooling facilities may have an adverse impact on the quality of inland surface and ground waters and on fish and wildlife.

8. An important consideration in the increased use of inland water for powerplant cooling or for any other purpose in the Central Valley Region is the reduction in the available quantity of water to meet the Delta outflow requirements necessary to protect Delta water quality objectives and standards. Additionally, existing contractual agreements to provide future water supplies to the Central Valley, the South Coastal Basin, and other areas using supplemental water supplies are threatening to further reduce the Central Valley outflow necessary to protect the Delta environment.

9. The California Constitution and the California Water Code declare that the right to use water from a natural stream or watercourse is limited to such water as shall be reasonably required for beneficial use and does not extend to the waste or unreasonable use or unreasonable method of use or unreasonable method of diversion. Section 761, Article 17.2, Subchapter 2, Chapter 3, Title 23, California Administrative Code provides that permits or licenses for the appropriation of water will contain a term which will subject the permit or license to the continuing authority of the State Board to prevent waste, unreasonable use, unreasonable method of use, or unreasonable method of diversion of said water.

10. The Water Code authorizes the State Board to prohibit the discharge of wastes to surface and ground waters of the State.

Principles

1. It is the Board's position that from a water quantity and quality standpoint the source of powerplant cooling water should come from the following sources in this order of priority depending on site specifics such as environmental, technical and economic feasibility consideration: (1) wastewater being discharged to the ocean, (2) ocean, (3) brackish water from natural sources or irrigation return flow, (4) inland wastewaters of low TDS, and (5) other inland waters.

2. Where the Board has jurisdiction, use of fresh inland waters for powerplant cooling will be approved by the Board only when it is demonstrated that the use of other water supply sources or other methods of cooling would be environmentally undesirable or economically unsound.

3. In considering issuance of a permit or license to appropriate water for powerplant cooling, the Board will consider the reasonableness of the proposed water use when compared with other present and future needs for the water source and when viewed in the context of alternative water sources that could be used for the purpose. The Board will give great weight to the results of studies made pursuant to the Warren-Alquist State Energy Resources Conservation and Development Act and carefully evaluate studies by the Department of Water Resources made pursuant to Sections 237 and 462, Division 1 of the California Water Code.

4. The discharge of blowdown water from cooling towers or return flows from once-through cooling shall not cause a violation of water quality objectives or waste discharge requirements established by the Regional Boards.

5. The use of unlined evaporation ponds to concentrate salts from blowdown waters will be permitted only at salt sinks approved by the Regional and State Boards. Proposals to utilize unlined evaporation ponds for final disposal of blowdown waters must include studies of alternative methods of disposal. These studies must show that the geologic strata underlying the proposed ponds or salt sink will protect usable groundwater.

6. Studies of availability of inland waters for use in powerplant cooling facilities to be constructed in Central Valley basins, the South Coastal Basins or other areas which receive supplemental water from Central Valley streams as for all major new uses must include an analysis of the impact of such use on Delta outflow and Delta water quality objectives. The studies associated with powerplants should include an analysis of the cost and water use associated with the use of alternative cooling facilities employing dry, or wet/dry modes of operation.

7. The State Board encourages water supply agencies and power generating utilities and agencies to study the feasibility of using wastewater for powerplant cooling. The State Board encourages the use of wastewater for powerplant cooling where it is appropriate. Furthermore, Section 25601(d) of the Warren-Alquist Energy Resources Conservation and Development Act directs the Commission to study, "expanded use of wastewater as cooling water and other advances in powerplant cooling" and Section 462 of the Waste Water Reuse Law directs the Department of Water Resources to "...conduct studies and investigations on the availability and quality of waste water and uses of reclaimed waste water for beneficial purposes including, but not limited to... and cooling for thermal electric powerplants."

Discharge Prohibitions

1. The discharge to land disposal sites of blowdown waters from inland powerplant cooling facilities shall be prohibited except to salt sinks or to lined facilities approved by the Regional and State Boards for the reception of such wastes.

2. The discharge of wastewaters from once-through inland powerplant cooling facilities shall be prohibited unless the discharger can show that such a practice will maintain the existing water quality and aquatic environment of the State's water resources.

3. The Regional Boards may grant exceptions to these discharge prohibitions on a case-by-case basis in accordance with exception procedures included in the "Water Quality Control Plan for Control of Temperature In the Coastal and Interstate Waters and Enclosed Bays and Estuaries of California.

Implementation

1. Regional Water Quality Control Boards will adopt waste discharge requirements for discharges from powerplant cooling facilities which specify allowable mass emission rates and/or concentrations of effluent constituents for the blowdown waters. Waste discharge requirements for powerplant cooling facilities will also specify the water quality conditions to be maintained in the receiving waters.

2. The discharge requirements shall contain a monitoring program to be conducted by the discharger to determine compliance with waste discharge requirements.

3. When adopting waste discharge requirements for powerplant cooling facilities the Regional Boards shall consider other environmental factors and may require an environmental impact report, and shall condition the requirement in accordance with Section 2718, Subchapter 17, Chapter 3, Title 23, California Administrative Code.

4. The State Board shall include a term in all permits and licenses for appropriation of water for use in powerplant cooling that requires the permittee or licensee to conduct ongoing studies of the environmental desirability and economic feasibility of changing facility operations to minimize the use of fresh inland waters. Study results will be submitted to the State Board at intervals as specified in the permit term.

5. Petitions by the appropriator to change the nature of the use of appropriated water in an existing permit or license to allow the use of inland water for powerplant cooling may have an impact on the quality of the environment and as such require the preparation of an environmental impact statement or a supplement to an existing statement regarding, among other factors, an analysis of the reasonableness of the proposed use.

6. Applications to appropriate inland waters for powerplant cooling purpose shall include results of studies comparing the environmental impact of alternative inland sites as well as alternative water supplies and cooling facilities. Studies of alternative coastal sites must be included in the environmental impact report. Alternatives to be considered in the environmental impact report, including but not limited to sites, water supply, and cooling facilities, shall be mutually agreed upon by the prospective appropriator and the State Board staff. These studies should include comparisons of environmental impact and economic and social benefits and costs in conformance with the Warren-Alquist State Energy Resources Conservation and Development Act, the California Coastal Zone Plan, the California Environmental Quality Act and the National Environmental Policy Act.

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2003 INTEGRATED ENERGY POLICY REPORT

CALIFORNIA
ENERGY
COMMISSION

DECEMBER 2003

Docket No: 02-IEP-1
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CALIFORNIA
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INTEGRATED ENERGY POLICY REPORT

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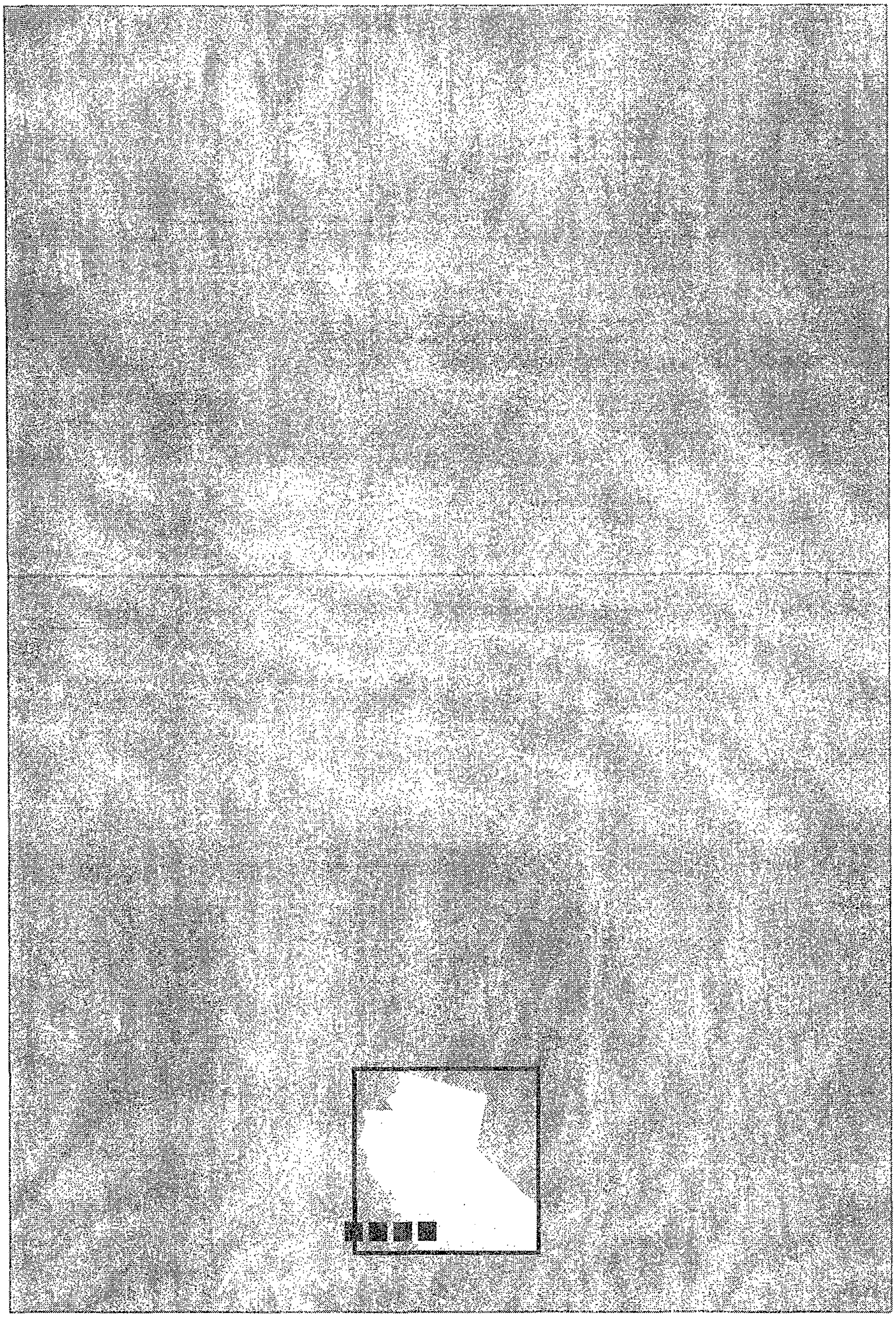

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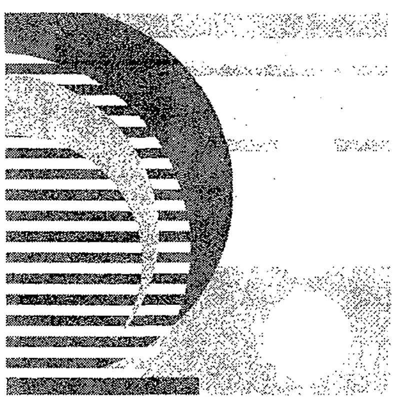
INTEGRATED ENERGY POLICY REPORT

EXECUTIVE *Summary*

As the fifth largest economy in the world, California is a nation state that runs on energy. Every day, we spend $82 million for gasoline and diesel, $82 million for electricity, and $22 million for natural gas. And although Californians use energy very efficiently, energy supplies have not necessarily been affordable, nor have they been reliable.

The state's flawed electricity restructuring experience caused prices to skyrocket, with Californians systematically removed from the grid on several occasions to avoid widespread blackouts. State government responded to the crisis by investing nearly $1 billion for new efficiency programs. Consumers also quickly flexed their power by replacing inefficient appliances, turning up their thermostats, and postponing energy-intensive appliance use during the hottest afternoons. The end result—California consumers reduced peak demand in 2001 by more than 10 percent, or approximately 6,000 megawatts.



Streamlined permitting procedures encouraged new power plant construction, and more than 9,500 megawatts of generation capacity were added in just three years— the largest expansion of the power plant fleet in California history.

Natural gas prices also rose at the height of the energy crisis to nearly $60 per million British thermal units, or Btus, more than 10 times the average price at that time. Working together, utilities and regulators increased the state's natural gas pipeline capacity by 25 percent and its total storage capacity by nearly 10 percent. These improvements allowed more natural gas to flow where needed, helping to moderate prices.

In contrast to price increases in the electricity and natural gas markets, price increases in the gasoline and diesel fuel markets are felt immediately at the pump. A refinery outage or pipeline failure, as happened this past August in Arizona, can quickly translate into high prices for gasoline and diesel fuel. This event left Californians paying an average of $2.10 for a gallon of gasoline. In past years, prices have spiked frequently, and twice this year, fuel prices have reached record levels. Typically, retail fuel prices rise rapidly, but drop slowly. With few viable alternatives, consumers wait for prices to settle.

Despite the current calm in the state's energy system, California's demand for energy is growing, fueled by an expanding population and a growing business sector. State government must act now to reduce demand, secure additional energy supplies, give consumers more energy choices, and build needed infrastructure improvements to protect California from future supply disruptions and high prices.

Electricity

Although electricity markets appear relatively stable for now, Californians still pay, on average, the third highest rates in the nation. Under average conditions, the state's electricity generation system has adequate supplies to meet demand for at least the next six years. Hot weather, coupled with other factors, however, could reduce reserves to very low levels as early as 2006.

To meet electricity demand, the state is taking steps to help ensure that preferred resources are available by implementing new efficiency standards and programs, evaluating the benefits of dynamic pricing, and aggressively developing renewable energy resources, as required under California's Renewables Portfolio Standard.

The Energy Commission believes that additional electricity resources should be procured using an integrated process that accounts for electricity demand and supply variations, efficiency gains, renewable energy potential, dependence on natural gas, and local reliability problems as in San Francisco and San Diego. The process must also account for expansions and upgrades of the bulk transmission system; strategies for retiring or modernizing older, less-efficient natural gas-fired power plants; as well as the benefits to the electric system of allowing consumers to choose their own electricity supplier and develop their own supply through distributed generation and cogeneration.

Natural Gas

Even though prices are currently stable, Californians now pay $5 per million Btus, roughly double the price consumers paid in the 1990s. California competes with other states for natural gas and depends on out-of-state resources for 85 percent of its supply. With the state located at the end of the interstate natural gas pipelines, California businesses and consumers are vulnerable to further natural gas supply disruptions and price volatility.

To help moderate demand, the state is increasing its energy efficiency programs, evaluating targeted retirements of less efficient power plants, and diversifying its fuel mix by accelerating the Renewables Portfolio Standard.

Looking forward, California must actively encourage infrastructure enhancements such as additional pipeline capacity, incentives for increased operation and use of in-state storage, in-state productive capacity, and nontraditional supply sources such as liquefied natural gas.

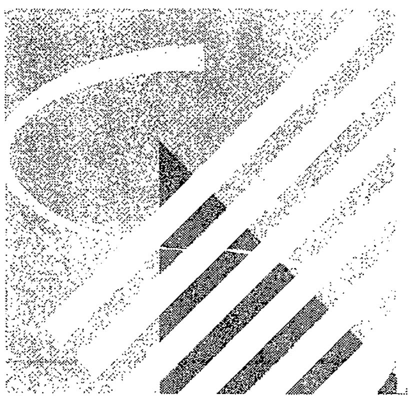
Transportation Energy

Even more pressing than the difficulties in the electricity and natural gas markets, tight supplies and volatility characterize California's gasoline and diesel market. In-state refineries operate near maximum capacity. Compounding the problem, California refiners must now use ethanol as an oxygenate to replace methyl tertiary butyl-ether (MTBE), which will further reduce in-state gasoline production.

In addition, California's import and storage systems have little, if any, excess capacity, and as demand for gasoline and diesel continues to grow, so will California's reliance on imports of crude oil, blending components, and refined petroleum products, further exacerbating California's tight gasoline and petroleum market.

In the short-term, the state must act to expand its petroleum infrastructure facilities, removing the barriers for industry to obtain needed permits in a timely manner, without jeopardizing environmental quality. But in the long-term, unless the state acts aggressively to change these emerging energy trends, California could face further supply disruptions and price volatility.

In July 2003 the Energy Commission and California Air Resources Board approved a joint strategy to reduce California's near total reliance on petroleum for transportation. This strategy depends primarily on raising new vehicle fuel economy standards and, to a lesser extent, increasing the use of alternative fuels and advanced vehicle technologies.



Recommended Actions for the Governor

The Energy Commission believes that state energy policies should capture the best features of both prudent and effective regulation and vigorous, open, competitive transparent procurement processes, and energy markets that provide adequate investment opportunities. These policies should promote affordable energy supplies; improve energy reliability; and enhance public health, economic well-being, and environmental quality.

The Energy Commission also believes that targeted research, development, and commercialization is a necessary means of introducing new, more efficient, and cleaner technologies into the market.

The following energy policy recommendations, highlighted from the body of this report, reflect these principles. Please note that various state government entities are currently undertaking or plan to conduct numerous actions that do not appear below as policy recommendations. However, these actions are critical to the formation of state energy policy and are discussed throughout this report.

Electricity

The state should:

- Incorporate the forecasts, resource assessments, and policy preferences of the *Energy Report* into an explicit resource adequacy requirement for all retail electricity suppliers to guide resource procurement.
- Ramp up public funding for cost-effective energy efficiency programs above current levels to achieve at least an additional 1,700 megawatts of peak electricity demand reduction and 6,000 gigawatt-hours of electricity savings by 2008.
- Rapidly deploy advanced metering systems if analyses show the results are favorable to the customer and will effectively decrease peak electricity use.

- Enact legislation to require that all retail suppliers of electricity meet the Renewables Portfolio Standard's goal of 20 percent of retail electricity sales and accelerate the target date for reaching the goal from 2017 to 2010.
- Explore through a collaboration between the California Public Utilities Commission and the Energy Commission the implications of a core/noncore market structure for electricity, with the goal of making recommendations in 2004.
- Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation, including cogeneration.
- Consolidate the permitting process for all new bulk electricity transmission lines within the Energy Commission, using the Energy Commission's power plant siting process at the Energy Commission as the model.

Natural Gas

The state should:

- Increase funding for natural gas efficiency programs to achieve an additional 100 million therms of reduction in natural gas demand by 2013.
- Encourage the construction of liquefied natural gas facilities and infrastructure and coordinate permit reviews with all entities to facilitate their development on the West Coast.
- Ensure that existing natural gas storage capacity is appropriately used to provide adequate supplies and protect prices.
- Initiate legislative hearings that will:

  1) examine the issue of gas quality and gas gathering as it relates to California gas production and

  2) determine whether additional legislative action is warranted to resolve the issues.

Transportation Energy

The state should:

- Adopt a goal of reducing demand for on-road gasoline and diesel to 15 percent below 2003 levels by 2020 based on identified strategies that are achievable and cost-beneficial.
- Build a coalition with other states and stakeholders to influence Congress and the U.S. Department of Transportation to double the combined fuel economy of new passenger cars and light trucks by 2020. If the federal government fails to revise corporate average fuel economy standards, California must reassess its petroleum reduction strategy.
- Increase the use of nonpetroleum fuels to 20 percent of on-road fuel consumption by 2020 and 30 percent by 2030 based on identified strategies that are achievable and cost-beneficial.
- Establish a one-stop licensing process for petroleum infrastructure, including refineries, import and storage facilities, and pipelines that would expedite permits to increase supplies of transportation energy products available to California while maintaining environmental quality.

Environment

The state should:

- Require reporting of greenhouse gas emissions as a condition of state licensing of new electric generating facilities.
- Account for the cost of greenhouse gas emission reductions in utility resource procurement decisions.
- Use sustainable energy and environmental designs in all state buildings.
- Require all state agencies to incorporate climate change mitigation and adaptation strategies in planning and policy documents.

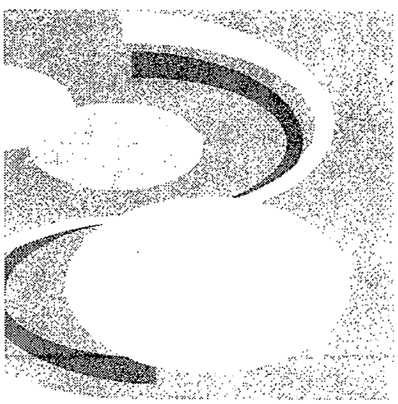
Some Guiding Thoughts

This *Energy Report* establishes a real-time, dynamic process for continuing dialogue on California's energy issues. The recommendations in this report represent an aggressive, wide ranging agenda for decision makers, businesses, and individuals. The Energy Commission believes that this report, along with its subsidiary volumes, lays the proper foundation for future action.

INTEGRATED ENERGY POLICY REPORT

SECTION ONE *Introduction*

In the fall of 2002, the Legislature passed Senate Bill 1389 [Chapter 568, Statutes of 2002, Bowen] requiring the Energy Commission to prepare a biennial integrated energy policy report, or *Energy Report*. This first *Energy Report* is due to the Governor in November 2003.



In passing SB 1389, the Legislature made clear that the *Energy Report* would be the foundation of energy policies and decisions affecting the state. The statute directs state entities to carry out their energy-related duties and responsibilities based upon the information and analyses contained in the *Energy Report*.

During the Spring of 2003, California's three principal energy agencies created a common vision to direct the future efforts at the California Public Utilities Commission (CPUC), the California Power Authority (CPA), and the Energy Commission. As envisioned in the plan, the *Energy Report* process represents "a critical step in identifying future statewide energy needs."[1]

The *Energy Report* consists of a Policy Report and three Subsidiary Volumes. In the Policy Report, the Energy Commission assesses the major energy trends and issues facing the state and uses these results to recommend energy policies that balance broad public interests to conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety.

The three Subsidiary Volumes address:

- Electricity and Natural Gas
- Transportation Fuels, Technologies, and Infrastructure
- Public Interest Energy Strategies

Report Development and Outreach

To develop these volumes, the Energy Commission staff undertook numerous technical studies examining all aspects of energy supply, production, transportation, delivery and distribution, demand, and pricing.

[1] California Energy Commission, *Energy Action Plan*, California Energy Commission, April 30, 2003, Sacramento, CA, pp. 1-4.

Throughout the spring and summer of 2003, the Energy Commission staff held many workshops on the three Subsidiary Volumes and supporting technical studies. At these workshops, technical experts critiqued the staff's work and provided valuable comments. The Energy Commission staff consulted with key federal, state, and local agencies in preparing these studies, involving more than 140 public and private stakeholders. The more than 3,000 pages comprising the Subsidiary Volumes and supporting technical studies lay the foundation for the Policy Report.

Because the Policy Report contains recommendations that will affect all Californians, the Integrated Energy Policy Report Committee conducted a series of hearings throughout California in early October 2003. The Committee received substantial and thoughtful comments from key public interest groups, energy developers, the business community, and general public. The Committee has studied these comments and used them to further shape the final Policy Report.

Strategies to Guide California's Energy Future

The Policy Report identifies four overarching strategies that serve as the basis of California's energy systems. It is imperative that the State of California take all necessary steps to implement the recommendations contained in this report. In doing so, the Governor, Legislature, and other state agencies should give great weight to strategies in addressing energy-related issues that:

- continue to harvest energy efficiency programs
- diversify fuels and fuel sources of petroleum and natural gas with alternative fuels and renewable energy
- offer consumers energy choices
- strengthen the state's energy infrastructure

These strategies will provide the stable environment necessary to attract investments to meet the demand for more energy resources and services and protect our economy and environment.

Updates to the Energy Report in 2004 and Beyond

In passing SB 1389, the Legislature intended this process to be a dynamic policy tool, requiring the Energy Commission to submit updates to the *Energy Report* every other year, beginning in November 2004. Work has already begun for a 2004 update in the following critical areas:

- re-powering, refurbishing, replacing old power plants
- transmission planning and permitting
- long-term renewable targets

Report Organization

Following this brief introduction, the *Energy Report* is organized into the following sections:

Section II	*Electricity*
Section III	*Natural Gas*
Section IV	*Transportation Energy*
Section V	*Stewardship of the Environment*
Section VI	*Concluding Observations*

INTEGRATED ENERGY POLICY REPORT

SECTION TWO *Electricity*

California's electricity system appears stabilized for now, but faces critical challenges for the years ahead.

There have been major investments to increase generating capacity in California and the surrounding Western states. These additions have helped to alleviate immediate concerns about adequate supply and price volatility. However, average retail prices for electricity in California are still among the highest in the nation. To address future supply and price concerns, California needs a balanced mix of supply and demand-side options that help to capture energy efficiency opportunities, allow for customer choice, diversify our electricity system, and strengthen our electricity infrastructure.

To maintain reliable supplies and reduce prices, California must establish resource adequacy requirements for all suppliers of retail electricity. The Energy Commission uses the term resource adequacy to encompass an integrated planning, procurement, and monitoring process for electricity suppliers in California. This process should assess the supply and demand for electricity, as well as the most prominent risks to the reliability of the system and electricity consumers in terms of electricity costs, and establish benchmarks to ensure that adequate planning reserves are maintained.

One of California's highest priorities is to ensure that electricity is used as efficiently as possible. Lowering per capita electricity consumption through standards and energy efficiency programs will benefit Californians substantially. In addition, reducing peak demand for electricity can also help to address consumer costs and environmental concerns, as well as avoid the need for investments in generation equipment that operates only a few hours a year.

California is increasingly dependent on natural gas for its electricity, and natural gas costs are a large component of wholesale electricity costs. Volatility in the natural gas markets can drive up wholesale electricity prices, especially during peak demand periods when gas-fired resources are the marginal supplies that establish the wholesale market clearing price. The state can reduce the demand for natural gas to generate electricity by aggressively developing energy resources required under California's Renewables Portfolio Standard (RPS).

California consumers and businesses could benefit from having more effective choices available to meet their unique electricity needs. This includes being able to choose an alternative energy provider through a well designed core/noncore retail market structure. In addition, consumers and businesses should be able to supply their own generation through the deployment of distributed generation and cogeneration. This will necessitate continued effort to remove barriers to their implementation and the establishment of effective electricity distribution system planning.

The state can further reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas-fired power plants and replace or repower these facilities with new, more efficient plants. The state must take care though, in targeting such retirements, as many older plants operate to provide critical grid reliability.

The state's bulk transmission system needs major upgrades and improvements. The broken transmission permitting process in the state must be fixed so that needed transmission investments can move forward.

Recent Trends in Meeting California's Electricity Needs

California's electricity system is a complex grid of electric power plants and transmission lines that meets the state's need for electricity by instantaneously balancing supply and demand. The California grid interconnects to the surrounding Western states, Mexico, and Canada, allowing utilities to exchange energy and share reserve support to the benefit of the broader region. This also means that problems in one area of the grid can have price and reliability impacts throughout the region. Ensuring adequate generation and transmission are critical to ensuring reliability and grid stability at reasonable prices.

As California's economy expanded in the 1990s, so did its electricity consumption. Although California's energy efficiency standards have slowed the growth of per capita electricity use, power plant development in California and the West did not keep pace with demand growth. This lack of investment in electricity infrastructure was largely a result of uncertainties surrounding the pending electricity market restructuring at the state and federal levels.

In the summer of 2000, as the energy crisis began, wholesale electricity prices began to increase dramatically. As the winter of 2000-2001 approached, the price of natural gas more than doubled, further exacerbating already high electricity prices. Prices continued to climb during the winter, and electric utilities throughout the West incurred enormous costs to purchase electricity.

The reliability of the California grid was in jeopardy numerous times throughout the summer of 2000 and, more surprisingly, during the winter of 2000-2001 when demand is typically low. Utilities were forced to institute systematic rotating outages on several occasions to maintain grid stability and prevent more severe and widespread blackouts.

Supply shortages and high prices during this energy crisis were exacerbated by transmission congestion problems. The transmission systems of the state's utilities were originally designed and operated to meet their own customer needs. Major investments in higher-voltage bulk transmission made during the 1960s through the early 1990s allowed utilities to import cheap power from the Pacific Northwest and Southwest regions. These upgrades also facilitated electricity transfers between utilities within the state.

In recent years, however, investor-owned utilities (IOUs) have not been successful in obtaining the necessary construction approvals for major bulk transmission upgrades to move power within the state and access imports from the remainder of the Western region.[2] As a result, congestion on the transmission system has become a more frequent occurrence since the mid-1990s. During the energy crisis, transmission congestion frequently hampered the effective transfer of electricity to meet demand at critical times and contributed to the run-up in wholesale prices.

Amid these serious problems, two factors emerged that played a key role in helping California through the summer of 2000. Despite not being paid for generation as a result of the adverse financial condition of the IOUs, cogeneration and renewable facility operators maintained relatively high levels of availability and were largely responsible for keeping the lights on during the darkest days of the crisis.

Also, in response to rising retail prices and statewide public information campaigns, Californians voluntarily reduced electricity consumption to unprecedented levels, shaving approximately 6,000 megawatts (MW)[3] off peak demand statewide. Surprisingly, recent analyses show that as much as half of these 2001 conservation efforts continued into 2002.[4]

For the next few years, California's electricity system appears to have sufficient planning reserves to balance supply and demand. Since 2001, more than 9,500 MW of generating capacity has come on-line, most new, efficient natural gas-fired generators. These additions constitute the largest expansion of the power plant fleet in California history.

Although wholesale prices are substantially lower than at the height of the energy crisis, this came at a cost. To ensure system reliability and control future price volatility, the state negotiated a series of long-term electricity supply contracts. The negotiated prices are much higher than current spot market prices. Furthermore, the contract terms have at times limited the operation of the system, contributing to higher wholesale costs. As a consequence, while the physical infrastructure currently provides reliable electricity, the prices that consumers pay for electricity are higher than in the 1990s and are among the highest in the nation.

Despite recent improvements in the electricity market as a whole, the Energy Commission is concerned about local reliability in San Diego and the San Francisco peninsula. Both areas experienced serious reliability problems during the energy crisis.

Not surprisingly, both areas have limited local generation and limited transmission capacity to access generation outside of those boundaries. These local reliability challenges warrant priority attention from local and state decision-makers.

[2] California Energy Commission, *Upgrading California's Electric Transmission System: Issue and Actions*, August 2003, Sacramento, CA, P100-03-011 p. 63.
[3] California Energy Commission, *Public Interest Energy Strategies Report*, October 2003, Sacramento, CA, P100-03-012D, p. 43. California Energy Commission, *The Summer 2001 Conservation Report*, pp. 12-14.
[4] *Public Interest Energy Strategies Report*, p. 43, Figure 3-6.

Electricity Outlook

Population and economic activity drive electricity consumption growth. Maintaining adequate supply reserves will be critical for meeting future electricity needs.

Under average weather conditions, the Energy Commission believes that California should have adequate supplies of electricity through 2009. However, because unusually hot weather conditions can significantly drive peak electricity demand, the Energy Commission is concerned about adequate supplies of electricity beginning in 2006. Under adverse weather conditions,[5] planning reserve margins could fall below seven percent in 2006 and even lower thereafter. Reserve shortages, according to the California Independent System Operator (CA ISO) could return as early as the summer of 2004 under "adverse conditions."[6]

Reserve margins can be affected by the retirement of older generating units. The CA ISO projects that 7,232 MW of generation capacity in California could be retired during the next several years,[7] while Dynergy, a merchant generator, has suggested that more than 10,000 MW may be retired as early as 2005 because of a lack of Reliability-Must-Run (RMR) contracts, contracts with the Department of Water Resources, or other power contracts.[8] In contrast, the Energy Commission has projected that 4,630 MW of existing capacity will likely retire through 2006.[9]

Notwithstanding all of these projections, the Energy Commission believes that planning reserve can improve through 2010, if California meets the goals in demand responsive programs, peak reduction programs, and the accelerated RPS.

Integrated Resource Planning, Procurement, and Monitoring Process

A reliable electricity system in California will depend on a resource adequacy process that goes beyond simply matching near-term demand with available generation resources. Resource adequacy requirements can best be achieved if forecasting and planning assessments, as well as procurement and monitoring activities, are fully integrated.[10] Policy and planning efforts must integrate energy efficiency, customer-side generation, and transmission upgrades necessary to bring additional renewable resources into the preferred resource mix. In addition, continuous monitoring efforts must be undertaken to ensure that planned resources are added as expected.

The resource planning process must also reflect the substantial risk and uncertainty in meeting future electricity demand. For example, there is risk in planning for average conditions. As we learned in 2000-2001, unexpectedly low hydroelectric and adverse weather conditions can profoundly influence the reliability and price of electricity. Adequately planning for these contingencies to ensure that cost-effective reserve options are available during low hydro and adverse weather conditions will help to prevent supply shortfalls and mitigate price volatility.

[5] Adverse weather conditions refer to a "hot temperature," 1-in-10 year weather scenario.

[6] CA ISO clarifies "adverse conditions" as low levels of hydroelectric power from the Pacific Northwest, higher than anticipated levels of generation outages inside the state, and the forced or economic retirement of older generation capacity. See CA ISO testimony at the Integrated Energy Policy Report Hearing, October 3, 2003.

[7] CA ISO, *California ISO Five Year Assessment (2004-2008)*, CA ISO, October 10, 2003, Folsom, CA.

[8] See testimony of Greg Blue (Dynegy) at Energy Commission Integrated Energy Policy Report Hearing, October 2, 2003.

[9] California Energy Commission, *Electricity and Natural Gas Assessment Report*, October 2003, P100-03-014, pp. 141-142.

[10] The Energy Commission also made a similar proposal in the CPUC long-run procurement proceeding R.01-10-024.

Also, economic activity varies cyclically, and these variations in electricity demand are likely to continue to be significant; the mix of resources may not produce as well as we anticipate. Some demand-side options depend on consumer behavior that may fall short of expectations. Similarly, the benefit of accelerating the development of renewable energy is clear, but funding may not be available to bring such benefits to fruition.

To ensure that resource adequacy is maintained, the Energy Commission proposes that an integrated planning, procurement, and monitoring process be established in collaboration with the CPUC, CA ISO, and the state's utilities and retail electricity suppliers. In the proposed process, the Energy Commission's information and analyses contained in the *Energy Report* would form the basis for long-term forecasting and supply-demand assessments. This would bring generation, efficiency, and transmission resource alternatives into a more integrated planning process than currently exists.

The CPUC's procurement process would be the means to authorize IOUs to secure long-term generation, renewable resource, and energy efficiency program resource additions. An expanded monitoring process would be created to ensure that a tight feedback loop exists to track progress for the preferred resource additions of energy efficiency, price responsive demand, distributed generation, and renewable resources, and make adjustments needed to ensure reliability.

This proposed planning, procurement, and monitoring process should result in improving electricity efficiency, diversifying the electric generation mix with renewables, leveraging opportunities for customer choice, and strengthening the electricity generation and transmission infrastructure, as called for below.

Recommendation for Resource Planning, Procurement, and Monitoring

The state should:

- Incorporate the forecasts, resource assessments, and policy preferences of the *Energy Report* into an explicit resource adequacy requirement for all retail electricity suppliers to guide resource procurement.

Improve Electricity Efficiency

Electricity price stability and reliability depends on harvesting every opportunity to improve end-use and system efficiency. The total amount of electricity consumed directly affects price volatility, the amount of average utility bills, and environmental impacts of the electricity system. Lowering per capita consumption through standards and energy efficiency programs will benefit Californians substantially.

Reducing peak demand for electricity also can mitigate consumer and environmental concerns as well as avoid the need for significant investments in generation equipment that will operate only a few hours a year. While some standards and energy efficiency programs can affect peak demand, a direct and immediate approach can be achieved through dynamic pricing.

Efficiency Standards and Voluntary Conservation

California's building and appliance standards are the most cost-effective means of achieving energy efficiency in the state. Since 1975, the annual peak savings have grown to a total 6,000 MW. By 2013, a cumulative total of building and appliance efficiency standards will have saved Californians $79 billion on their utility bills.[11] Further, since 1977 energy efficiency in California has increased economic growth, benefiting the state's economy by $875 to $1,300 per capita.[12]

Voluntary energy efficiency programs and individual conservation efforts are the other major sources of energy savings. These programs and efforts are fueled by education, technical assistance, monetary incentives, and tax credits. During the summer of 2001, consumers reduced their electricity consumption dramatically in response to public education campaigns like Flex Your Power. That summer, between 70 to 75 percent of the peak load reductions came from consumer conservation efforts, while 25 to 30 percent came from energy efficiency investments.

The Energy Commission and the CPUC are collaborating on a plan to improve the operation of energy efficiency programs, carefully ramping up program funding for electricity efficiency from the current level of $230 million to double this amount by 2008 and triple this amount by 2013.[13] Over the next two years, the CPUC will oversee the expenditure of $512 million in public funding. They will reassess program administration and incorporate efficiency into their procurement process. By spending about $5 billion over 10 years, the state would save consumers over $15 billion.

Conventional, off-the-shelf technology can produce energy savings in existing buildings. In fact, the bulk of the energy efficiency funds collected under the Public Goods Charge has been spent on existing buildings. The Energy Commission is developing strategies to achieve additional savings in existing buildings. A mix of voluntary and regulatory approaches that supplement current incentive programs may be the most effective plan. The promotion of programs like the Energy Efficient Mortgage can tap into private funds for cost-effective investments in energy efficiency in the residential sector.

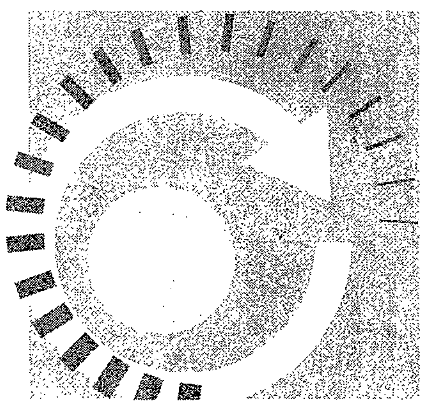
Achieving the most economical energy savings requires efficient program design, effective feedback, widespread customer participation, and reliable program funding. California's energy agencies will undertake a rigorous, ongoing monitoring and evaluation program to ensure that the savings and benefits from conservation and efficiency programs are delivered. Programs not meeting their targets will be modified or eliminated.

The Energy Commission is proposing program goals for energy efficiency savings. These targets would only be converted into firm resource plan additions when programs have been funded and an implementation method has been established. These programs would also be adjusted as monitoring and evaluation results are obtained. The staff analysis suggests that peak demand statewide could be reduced an additional 1,700 MW and that consumption could be reduced 6,000 gigawatt-hours by 2008 by doubling current energy efficiency funding levels.[14]

[11] *Public Interest Strategies Report*, pp. 40-41.
[12] Mark Bernstein, et al., RAND, *The Public Benefits of California's Investments in Energy Efficiency*, March 2000.
[13] California Energy Commission, *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, October 2003, P100-03-021.
[14] *Public Interest Strategies Report*, pp. 45-49.

Dynamic Pricing

In California, the highest peaks in electricity demand are caused almost exclusively by air conditioning during unusually hot weather occurring a few times each summer (50-100 hours per year).



Traditionally, these "super peak" loads have been met by peaking power plants, either combustion turbines or hydro generators. In emergencies, electric services can be voluntarily interrupted at industrial and commercial business or by turning off residential air conditioners. As a last resort, rotating outages have been employed to prevent the entire system from collapsing, as it did in the Northeast in August 2003.

However, dynamic pricing offers a different tool for reducing peak demand before an emergency occurs and the system drops below the operating reserve minimums. Dynamic pricing provides consumers with various pricing structures that send a "real-time" price signal, which reflects the actual cost of generating electricity, whereby consumers are often motivated to shift their electricity use from peak times to avoid high electricity rates.

In 2001 and 2002, real-time meters were installed for most large customers. These meters, combined with new communication and control systems, work together to reduce energy use when the price of electricity goes up. Several pilot programs offered customers incentives to use them during periods of peak demand. These customers effectively reduced peak load and increased reliability at times of greatest stress on the system.

Real-time meters need real-time or other dynamic pricing tariffs and programs to be effective. At present, these are only available on a limited basis. In September 2003 the Energy Commission, with input from the CPUC, prepared a report on the feasibility of dynamic pricing, which recommends a process to provide all electricity customers with a choice of flat, inverted tier, time-of-use, or dynamic pricing rates by 2009.[15] While the report found that these tariffs and programs are feasible, the extent to which they can be implemented universally is still unclear. The report recommends continued collaborative assessment with the CPUC to gain a more complete understanding of the extent to which dynamic pricing is appropriate for various types of customers.

[15] The Energy Commission adopted the SB 1976 report addressing the feasibility of dynamic pricing on October 22, 2003.

The CPUC has adopted an initial set of dynamic pricing tariffs and programs for larger customers to use with their real-time meters. The IOUs are now testing a pilot project for residential and small commercial customers. The results of these activities will be available in 2004. The next steps are to determine if the real-time meters will pay for themselves with savings from reducing the state's peak energy use with the correct pricing structures, and along with creating additional tariffs necessary to achieve the long term goals for price responsive demand adopted by the CPUC.[16]

Recommendations to Improve Electricity Efficiency

The state should:

- Ramp up public funding for cost-effective energy efficiency programs above current levels to achieve at least an additional 1,700 MW of peak electricity demand reduction and 6,000 gigawatt-hours of electricity savings by 2008.
- Standardize and increase the evaluation and monitoring of energy efficiency programs to ensure that savings and benefits are being delivered.
- Implement appropriate mandates, incentives, and funding to maximize the energy efficiency potential of existing buildings.
- Rapidly deploy advanced metering systems if analyses show the results are favorable to the customer and will effectively decrease peak electricity use.
- Implement sufficient real-time and dynamic pricing tariffs to satisfy the goal of 5 percent of system peak load.

Diversify the Electric Generation Mix with Renewables

California's RPS is the centerpiece of the state's strategy to diversify our electricity system. Partly in response to concerns about growing natural gas dependence, the Legislature passed Senate Bill 1078 [Chapters 516, Statutes of 2002, Sher] establishing the RPS. The RPS requires all retail suppliers of electricity in the state to develop a RPS program and that IOUs supply at least 20 percent of their sales from renewable energy resources by 2017. To the extent that electricity generated from renewable resources is sold under long-term contracts, it is immune to fluctuating natural gas prices and helps to stabilize the market, providing real economic benefit.[17]

[16] CPUC Decision, D.03-06-032, San Francisco, CA, April 2003.
[17] *Public Interest Energy Strategies Report*, pp. 101-102. Also, Standard Contract Terms and Conditions for the RPS are discussed in the June 19 CPUC Decision 03-06-071, *Order Initiating Implementation of the Senate Bill 1078 Renewables Portfolio Standard Program*, p. 55.

The state's IOUs have already made significant strides in meeting RPS targets through interim solicitations conducted under the CPUC's resource procurement proceeding. Southern California Edison (SCE) recently reported monthly purchases of renewable resources which exceed 20 percent for May and June 2003; that it expects to achieve "nearly 20 percent" for the full year 2003 and that it expects to exceed 20 percent each year thereafter. San Diego Gas & Electric (SDG&E) and Pacific Gas & Electric (PG&E) have also reported that they expect to meet their RPS targets well in advance of the 2017 goal. In this context, accelerating the goal of meeting the RPS target by 2010, rather than 2017, should be readily achievable by the IOUs.

In light of the progress already being achieved under the RPS program, the Energy Commission believes that the RPS should extend to all retail suppliers of electricity. The Energy Commission also believes that development of more ambitious longer-term RPS goals for the post-2010 period is warranted. In establishing more ambitious RPS goals, the specific resource mix of each utility, transmission infrastructure, and the availability of cost-effective renewable resources should be taken into account. This may mean that individual utility targets should be developed to replace the more generic statewide RPS goals already established by the Legislature. Development of more ambitious RPS goals will be part of the 2004 *Energy Report* update activities.

Recommendation to Diversify the Electricity System

The state should:

- Enact legislation to require that all retail suppliers of electricity meet the RPS goal of 20 percent of retail electricity sales and accelerate the target date for reaching the RPS goal from 2017 to 2010.

Leverage Opportunities for Customer Choice

California's effort to restructure the electricity industry had its roots in the interest of some customers to manage their electricity expenses individually and determine generation resource preferences. This was accomplished in one of two ways. Consumers could choose a retail supplier of electricity other than the local utility; or, through advances in distributed generation technologies, consumers can supply their own electricity by cogeneration and self-generation, which contributes to electrical grid reliability and security.

Retail Customer Choice

Currently, California's electricity customers are limited in their ability to choose their electricity suppliers, but this has not always been the case. Beginning in 1998, most Californians were allowed to choose an electricity supplier other than their local utility through "direct access." At its peak, direct access represented 16 percent of all sales and 25 percent of all large customers' sales. As a result, local utilities found themselves with excess generation when customers left for these alternative suppliers.

However, as electricity prices rose during the energy crisis, many direct access providers could no longer offer savings to customers and dropped out of the market. Local utilities suddenly found themselves with insufficient generation when those same customers unexpectedly returned. Rising wholesale prices and the declining financial condition of the IOUs made it difficult to secure adequate supplies of electricity.

Legislation enacted in early 2001 authorized the state, through the Department of Water Resources (DWR), to procure electricity on behalf of the IOUs and issue bonds to cover the costs of purchasing the power.[18] It also directed the CPUC to suspend direct access. In its subsequent decision, the CPUC stated that "Suspending the right to acquire direct access service will assist in issuing these bonds at investment grade, by providing DWR with a stable customer base from which to recover its costs."[19]

Questions now are being asked whether that ability to choose is still beneficial to large customers and whether the suspension on direct access should be removed. If the answer to these questions is "yes," the state should examine the natural gas market structure as a possible model for the electricity sector.

However, while direct access was voluntary for electricity customers, customer choice in the natural gas market is different. Large natural gas customers are assigned to the "noncore" customer group, while smaller customers are designated as "core" customers. Local gas utilities are required to serve core customers, while noncore customers can shop around to purchase the cheapest natural gas supplies.

This model has been successful because it identifies a stable, unchanging group of customers. Because natural gas utilities are protected from customers who might return to their systems without adequate notice, the natural gas utilities are able to secure natural gas supplies effectively, plan storage, and adequately cover their costs effectively.

Conceptually, a core/noncore structure in the electricity market, with very explicit contractual conditions for customers to return to their original supplier, could allow utilities to plan with more certainty. At the same time, such a structure may provide merchant generators, who already have permits to build new power plants, with a customer base that is willing to sign long-term contracts. Variations on this core/noncore structure for electricity customers are beginning to be implemented in restructured markets in the East. The existence of such a market may also encourage generators to take merchant risk.

System reliability is important for these customers as well. Noncore customers and businesses must meet specific reserve requirements without burdening other customers, either by cogenerating/self-generating or by buying electricity through another energy provider. All customers would be equally responsible for securing electricity supplies to maintain the system's reliability.

Many critical issues must be resolved, however. The CPUC staff is studying changes to the market structure and their implications for ratepayers, reliability, the environment, investor confidence, and market volatility, including the core/noncore model. The study is expected to be completed in March 2004.

[18] Assembly Bill 1x1, Chapter 4, Statutes of 2001, Keeley.
[19] CPUC Decision 01-09-060, September 20, 2001.

Distributed Generation

Although different from direct access, distributed generation offers consumers a range of choices for securing their electricity supplies. Distributed generation, including cogeneration and self-generation, has tremendous potential to help meet California's growing energy needs as an additional generation source and an essential element of customer choice. Its use offers potential benefits that extend to customers, utilities, and the system as a whole and can be used strategically to meet the policy objectives of the RPS and reduce greenhouse gases.

From a customer perspective, distributed generation allows customers to choose between electricity supplied via traditional utility grid service, electricity provided by a non-utility generator located at or near the point of consumption, or by some combination of the two. Benefits include improved reliability and power quality, peak-shaving options, security, and efficiency gains through the avoidance of line losses and the use of waste heat for heating and/or air conditioning.

Distributed generation also offers benefits to the utilities. While the actual benefits of each project will vary based on the location of the generating facility, distributed generation can benefit utilities by deferring transmission and distribution construction, reducing resource acquisition costs, and supporting the level of ancillary services offered.

To date, California has addressed many technical, institutional, and regulatory barriers inhibiting the effective deployment of distributed generation. During the past three years, the California Air Resources Board (CARB) adopted emissions regulations and guidelines for distributed generation technologies, while the CPUC adopted standardized interconnection rules. In response to industry concerns, the CPUC also exempted 3,000 MW of distributed generation over the next 10 years from the Cost Responsibility Surcharge or "exit fee" imposed on customers who leave the grid. The CPUC's decision gives preference to the cleanest technologies. The Energy Commission adopted regulations to determine how and which customers qualify for the exemption. These regulations will be implemented by February 2004.

A new collaboration between the Energy Commission and CPUC will begin shortly to address outstanding issues in establishing a transparent electricity distribution system planning process. Utilities are currently required to consider distributed generation as part of its distribution system planning process.[20] However, it is not clear how this process is actually implemented, and in particular whether it adequately addresses the benefits and costs of distributed generation. The collaboration will be part of a new CPUC rulemaking, a follow-up to the CPUC's February 2003 policy decision. The two agencies are also committed to working together to target research to identify cumulative system impacts and examine issues associated with new technologies and their use.

[20] Section 353.5 of the Public Utilities Code states that "Each electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost."

Ultimately, the long-term successful deployment of distributed generation will require focused policy direction. Much of the focus should be targeted at increasing consumer awareness about the benefits of using distributed generation, providing financial incentives to offset the cost of installation, and funding research to advance technology so that incentives are eventually no longer needed. Consistent with the desire to implement the RPS effectively, statewide incentives should reflect a preference for renewable resources. In making these commitments, policy makers must ensure that the regulatory rules governing the use of distributed generation do not in themselves create new barriers to entry.

Recommendations to Leverage Customer Choice

The state should:

- Explore through a collaboration between the CPUC and the Energy Commission the implications of a core/non-core market structure for electricity, with the goal of making recommendations in 2004.
- Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation.

Strengthen the Electricity Infrastructure

Despite the significant expected gains in efficiency and reductions in peak demand, at some point the state will need new generating capacity. The type of new plants will depend on the effectiveness of an integrated resource planning, procurement and monitoring process. Additionally, the extent to which the need for and location of new transmission capacity is identified and ultimately permitted will determine whether the state will continue to rely largely on conventional technology or broaden the mix of cleaner renewable resources.

Generation

To achieve the policy goals for electricity outlined in the *Energy Report*, the CPUC's procurement process must be open, competitive and transparent, and incorporate the results of the Energy Commission's resource planning, forecasts, and assessments. The state's three large IOUs—PG&E, SCE, and SDG&E who serve over 80 percent of the state's demand—are actively developing both interim and long-term resource procurement plans under the supervision of the CPUC. It appears that the CPUC may authorize some degree of long-term contracting for the three IOUs in its forthcoming procurement decision even if a comprehensive resource adequacy framework is not yet established. However, the Energy Commission believes that it is critical that progress be achieved in establishing a resource adequacy framework for the state.[21]

[21] FERC has deferred to the state to develop a resource adequacy requirement as part of the CA ISO's market redesign. In a recent decision (ER02-1656-015, et al.), FERC noted the importance of the resource adequacy to signal the need for new infrastructure in the electric power markets and its importance to overall market design and established timelines for when the CA ISO must make a filing on resource adequacy following the CPUC's procurement decision expected in December 2003.

California also needs to examine the efficiency of its existing fleet of power plants. Concerns have been raised that the aging fleet of power plants still operating in the state are more polluting and less efficient than modern power plants. Many of these older plants are presently needed to maintain local reliability because of their location in the grid. Many have RMR contracts with the CA ISO or long-term DWR contracts. Additionally, some of the RMR and DWR contracts provide that pollution control upgrades can be paid for through contract revenue streams, allowing renovation to meet air district requirements.

Those facilities paid under RMR or other contracts are unlikely to shut down unless and until their reliability function is provided by a new plant or is no longer needed because of upgrades to the transmission system. However, uncertainty does exist regarding the continued future operation of older facilities that either do not have RMR contracts or for which RMR contracts are not renewed. The Energy Commission is undertaking a detailed study of aging power plants and the costs, benefits, and strategies for their replacement as part of the 2004 *Energy Report* update proceeding.

Transmission Planning

California's transmission system links power generation resources with customer loads in a complex electrical network that must balance supply and demand on a moment-by-moment basis to reliably deliver the lowest cost generation to consumers. The transmission system must be efficient and robust to facilitate competitive markets, pool resources for ancillary services, and provide emergency support in the event of unit outages or natural disasters. California's transmission system must deliver these benefits in a manner that maximizes their value while minimizing negative environmental and other impacts as the system is upgraded to respond to changes in generation and load patterns. This includes the state's commitment to develop renewable generation aggressively through its RPS program.

Under existing generation and load conditions, the transmission system regularly experiences congestion on major paths that prevents its optimal economic operation. Also, transmission constraints in major load centers such as San Francisco and San Diego affect both the economic and reliable operation of the system. Transmission upgrades, generation additions, and demand-side management actions may provide solutions to these problems. However, the existing transmission planning and permitting processes have not provided effective and timely mechanisms for bringing forward such projects to provide California with a more robust and reliable transmission system.

The state currently does not have an official role in transmission system planning. Transmission planning for about 80 percent of the California grid is the responsibility of the CA ISO, and California IOUs must participate in the CA ISO planning process. However, publicly owned utilities and federal agencies do not have to participate and in most cases, they have chosen not to do so. For the most part, publicly owned utilities and federal agencies propose, plan, and build transmission projects to meet their own reliability and economic needs. Merchant transmission line developers may propose economic projects for consideration in the CA ISO process.

As a result of the fragmented approach to transmission planning in the past, a statewide perspective has not been brought to the table, regardless of ownership. Consequently, the planning process has addressed issues important to the transmission owners and CA ISO, but may have overlooked issues that are vital to the state's broader interests. Some of these statewide interests include future renewable resource development, right-of-way needs, system reliability, and the efficient use, environmental performance, and economic expansion of the existing system.[22]

California must have accurate and comprehensive assessments available to ensure the timely planning and ultimate permitting of needed transmission projects. There is a critical need for improvement in the analytical methodologies that are used for evaluating the costs and benefits of transmission projects. Current analytical methodologies used in project planning typically employ short-term analytical horizons, economic valuation methodologies that do not recognize strategic benefits, and cost/benefit evaluations that unduly discount long-term project benefits.[23]

Additionally, current analytical approaches typically assume average conditions only and therefore fail to recognize the cost of unforecasted low probability, but high impact events, such as droughts, regional blackouts, and temperature extremes. Experience with past transmission investments has shown that while there is tremendous angst in regulatory proceedings over project need, including costs and benefits, transmission lines can pay for themselves in just a few years because of these low probability, but high impact events. Given the longer lead times required for transmission projects and the locational impacts of potential new power plants, modernizing and upgrading the bulk transmission grid should be a centerpiece of the state's electricity planning process.

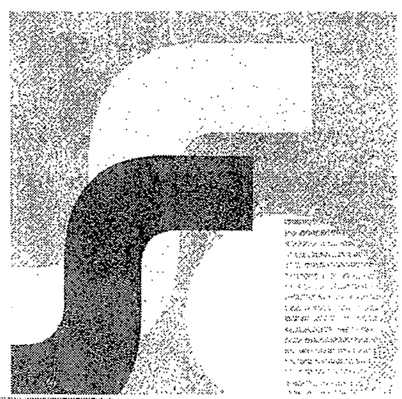
To ensure that California meets this goal, the Energy Commission is implementing a fully collaborative state transmission planning process including the CA ISO, CPUC, and utilities. The process will be implemented in 2004 to determine the statewide need for bulk transmission projects and assess and compare the costs, benefits, and alternatives to individual projects. The process, which will build on the CA ISO's annual transmission plan, will evaluate transmission, generation, and demand-side alternatives to help reinvigorate the state's transmission planning process. The goal of this effort will be to ensure that expansion of the grid is made on a timely basis, and that statewide objectives are considered in determining transmission investments that best meet the needs of California.

The transmission planning and assessment process will be carried out during the 2004 *Energy Report* update, will be integrated with other electricity analyses and policy work, and use appropriate assumptions for demand and price forecasting and supply options. The process will evaluate broader strategic benefits than those currently considered. This will include low-frequency, high severity events; strategic values of transmission, such as expanded access to regional markets; enhancement of grid reliability; insurance against major contingencies; and regional alternative economic approaches to evaluation of project costs and benefits. This process will consider the costs and benefits of generation and demand-side management (DSM) as alternatives to transmission.

[22] *Upgrading California's Electric Transmission: Issues and Actions*, pp. 61-62.
[23] Ibid., p.73. California Energy Commission Consultant Report prepared by Consortium of Electric Reliability Technology Solutions, *Planning for California's Future Transmission Grid, Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations*, October 2003, Sacramento, CA, P700-03-009, p. 15.

Transmission Permitting

The permitting of transmission lines in California currently suffers from jurisdictional responsibilities that are fragmented and overlapping, environmental analyses that are inconsistent, and inadequate consideration of regional and statewide benefits. As a result, existing permitting processes create duplication between local, state, and federal agencies, delay in approvals, and denial of needed projects. Because of the existence of several permitting jurisdictions, it may be difficult for a lead agency to conduct an environmental review of the entire project under the California Environmental Quality Act (CEQA).



Merchant transmission projects are subject to review by all local land use agencies whose jurisdictions they cross. However, publicly owned utilities are responsible for performing their own environmental reviews, regardless of the local jurisdictions they cross, potentially calling into question the objectivity and fairness of how transmission projects get reviewed and by whom. Publicly owned utilities determine if proposed projects are needed for reliability and economic purposes based on benefits and costs to their own ratepayers.

Projects proposed by IOUs are subject to the CPUC's review, whose environmental review process has typically depended on external consultants rather than in-house professional staff. This has led to inconsistencies in environmental review and analysis between different transmission line projects, adding time and complexity to the review process. In addition, the legalistic nature of the CPUC process has often inhibited effective involvement of the general public.

The CPUC review of the need, under the Certificate of Public Convenience and Necessity (CPCN), for IOU transmission projects has, in many cases, been protracted and subject to multiple delays. As a result, only a very small number of transmission projects that require a CPCN have been constructed by IOUs in recent years.

The CPUC assesses the need for reliability and economic projects proposed by IOUs based on limited cost/benefit analyses that focus primarily on impacts to the sponsoring utility even though the CA ISO charges these costs to all users of its grid. In the CPCN process, the CPUC often re-examines planning issues, refusing to accept the CA ISO's determinations in the planning process. As a result, projects with regional or statewide benefits that could help the state mitigate market power, stabilize electricity prices, and improve the reliability and environmental performance of the electricity system have been denied permits by the CPUC or suffered long delays in the process because of an inadequate assessment of these benefits.

As an example, in the late 1980s, the CPUC denied IOU participation in the California-Oregon Transmission Project. The project was subsequently built by municipal utilities, and now provides critical capacity to their customers for importing low cost electricity from the Pacific Northwest. Current projects that have experienced similar difficulties with the CPUC process include the Path 15 upgrade and the Valley-Rainbow project. Similar problems are likely to plague future projects.[24]

[24] *Upgrading California's Electric Transmission System: Issue and Actions*, p. 63.

Ensuring reliable and reasonably priced electricity supplies—increasingly from renewable resources—depends on a well-maintained and adequate transmission and distribution system. The state must reinvigorate its planning, permitting, and funding processes to ensure that necessary improvements and expansions to the distribution system and the bulk electricity grid are made on a timely basis.

To meet this goal, permitting for new bulk electric transmission lines should be consolidated with, and modeled after, the Energy Commission's current licensing process for generation. This step, as identified in the Energy Commission's collaborative transmission planning process, would include public input and a comprehensive, independent professional staff review in a specific time frame.

This consolidation is consistent with the Little Hoover Commission's 1996 recommendation[25] that generation and transmission permitting be consolidated, and the State Auditor's 2001 recommendation[26] that the Legislature institute a coordinated electricity transmission siting process similar to the Energy Com-mission's generation siting process. Given the critical need to upgrade and expand the state's transmission system, the Governor should expedite the consolidation through the exercise of his agency reorganization powers, using the Little Hoover Commission process.[27]

Recommendation to Strengthen the Electricity Infrastructure

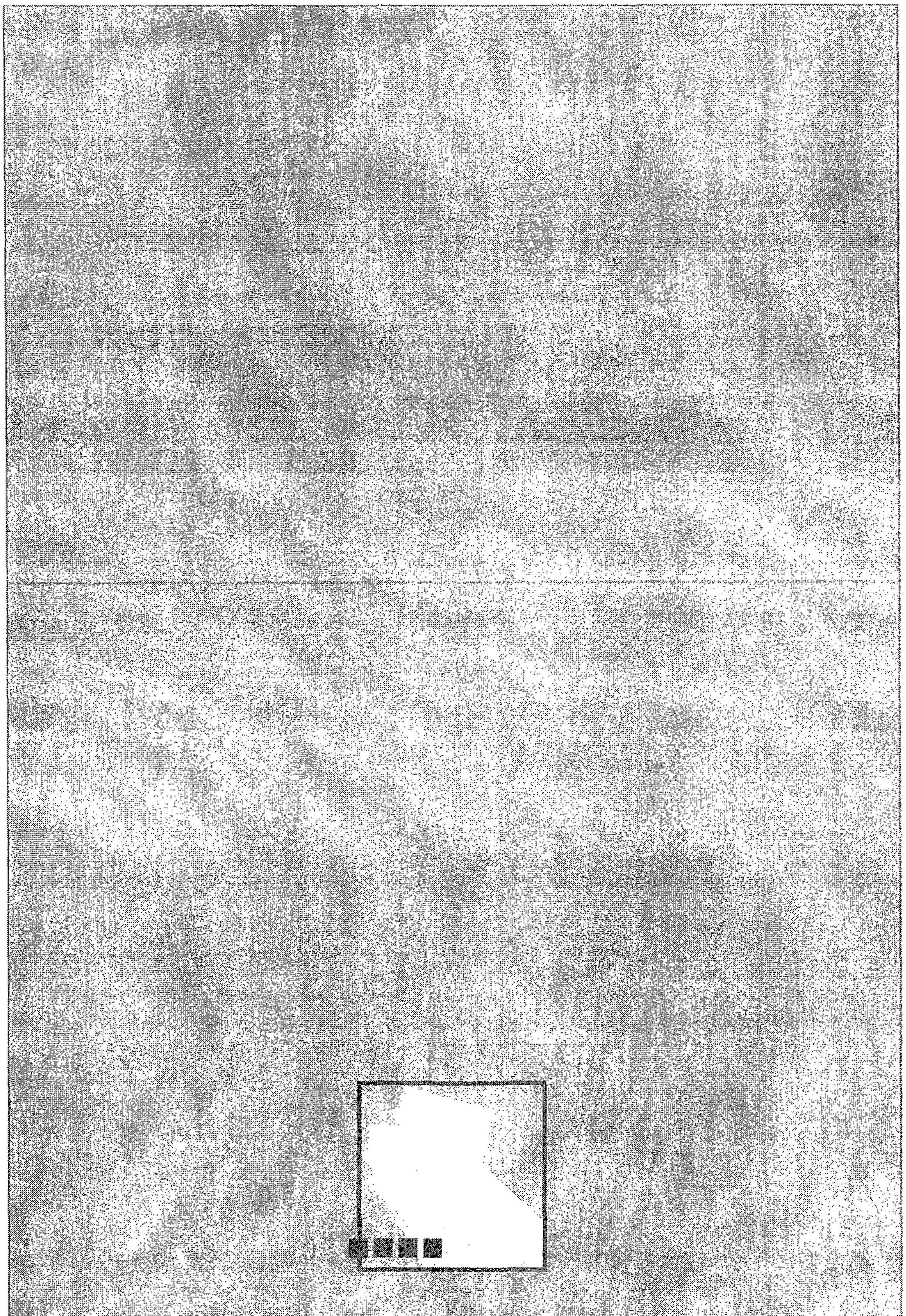
The state should:

- Consolidate the permitting process for all new bulk electricity transmission lines within the Energy Commission, using the Energy Commission's power plant siting process as the model.

[25] *When Consumers Have Choices: The State's Role in Competitive Utility Markets*, Little Hoover Commission, December 1996.

[26] *Although External Factors Have Caused Delays in Its Approval of Sites, Its Application Process Is Reasonable*, California State Auditor, Bureau of State Audits, August 2001.

[27] Government Code Section 12080.1.

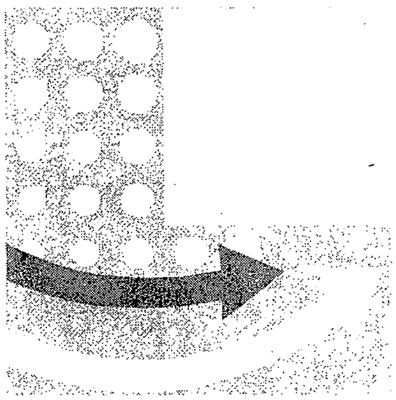


INTEGRATED ENERGY POLICY REPORT

SECTION THREE *Natural Gas*

California is the nation's second largest consumer of natural gas. Policy makers have questioned California's increasing dependence on natural gas, with demand for natural gas increasing to meet the needs of the growing power generation market, increasing price volatility, and California producers who are able to satisfy only 15 percent of statewide demand.

In general, the higher overall level of natural gas prices nationwide during the past year calls into question the point of view, developed during the 1980s and 1990s, that natural gas will be plentiful and cheap into the foreseeable future. Our current assessment is that natural gas supplies will continue to be available but at much higher prices than previously anticipated.



Recent Trends in Meeting Natural Gas Demand

In the past three years, California consumers have experienced two significant natural gas price spikes. In the winter of 2000-2001, gas prices were high throughout the country, but much higher in California. Driven by record low hydroelectric imports and underutilized storage, prices regularly exceeded $8 per million Btus at the California border and peaked at nearly $60 per million Btus.[28] California consumers' natural gas bills increased dramatically relative to consumers in other parts of the nation.

A price spike last winter once again increased natural gas bills to consumers. This time, however, California natural gas users fared well compared to consumers in the rest of the country. National spot prices for natural gas tripled in late February, driven by a prolonged cold snap in the Northeast, concerns about the impacts of war in Iraq, and low nationwide storage levels. Prices in California were also affected, rising above $9 per million Btus at the height of the price spike. However, California's relatively high storage inventories and unseasonably warm weather allowed prices to return to pre-spike levels relatively quickly and allowed them to stay below national levels.[29]

To focus greater attention on mitigating the potential for future price spikes, the California state agencies involved in natural gas issues formed the Natural Gas Working Group. The group meets regularly to keep the agencies well-informed on key natural gas issues, coordinate development of policies affecting natural gas use, and provide regular reports to the Governor's office on impending issues. The Group has allowed the state's activities in natural gas production, purchasing, permitting, regulation, environmental protection, and policy to be relatively well integrated.

[28] California Energy Commission, *Natural Gas Market Assessment*, California Energy Commission, August 2003, Sacramento, CA, P100-03-006, p. 27.
[29] Ibid., p. 2.

Natural Gas Outlook

Natural gas demand in California is projected to increase as a result of the growing use of natural gas for electric generation. This trend is even greater in the other western states. Natural gas demand for uses other than electric generation is expected to grow at only one-half percent per year in California over the next ten years, compared to a 1.5 percent annual growth rate in natural gas consumption in the electricity generation sector.[30]

The Energy Commission forecasts that, under average annual conditions, interstate pipeline capacity is adequate to meet demand through 2013 in Southern California and through 2007 in Northern California. However, meeting peak day demand under extreme weather conditions may require infrastructure investments earlier.[31]

Increasing Energy Efficiency in the Natural Gas Marketplace

As stated previously, Californians are energy efficient, aided by the state's stringent building and appliance standards. However, these achievements are not enough and more can be done to save energy.

The integrated nature of the natural gas and electricity markets suggests that programs targeted at cutting both peak and overall electricity use will also have a significant impact on reducing statewide natural gas consumption. Reductions during peak summer hours will have a great impact on ratepayer costs and price volatility, since electricity costs are most affected by underlying gas prices during these periods. Additional funding, targeted specifically at natural gas demand reductions, would yield significant cost-effective reductions.[32]

Beyond measures that individual consumers and businesses can take to conserve, electricity generators could retire older, less-efficient natural gas-fired power plants and replace or repower them with new, more efficient ones. Unfortunately, many of these plants are presently used to maintain system reliability.

Hence, before California can retire or replace existing power plants, it must examine the contractual arrangements that dictate their use. Many of these older power plants have RMR contracts with the CA ISO or long-term DWR contracts. To replace the aging power plants now used for reliability purposes, their cleaner, more efficient upgrades or replacements must receive similar financial incentives that recognize their benefits to local reliability and California's overall grid system. This issue will be further addressed as part of the 2004 *Energy Report* update proceeding.

Cogeneration offers another low-cost, low-emission option for the efficient use of natural gas. By creating both electric and thermal energy, cogeneration plants can achieve heat rates that "match or exceed the heat rates of new gas-fired combined-cycle power plants."[33] Cogeneration is a major element in the state's energy system, contributing more than 6,300 MW.[34]

[30] Ibid., p. 14.
[31] Ibid., p. 103.
[32] *Public Interest Energy Strategies Report*, p. 45.
[33] See written testimony of Scott Hawley, Watson Cogeneration Company, October 14, 2003, p. 3.
[34] See written testimony of the California Cogeneration Council, October 14, 2003, p. 2.

Recommendation for Natural Gas Efficiency

- Increase funding for natural gas efficiency programs to achieve an additional 100 million therms of reduction in natural gas demand by 2013.

Leveraging Opportunities for Customer Choice

Retail customer choice has been available to California natural gas consumers in many respects since 1988. At that time, driven by the growing movement for a competitive natural gas market and interest in building interstate pipelines into the state for the first time, the CPUC approved a mechanism whereby customers could procure natural gas from any energy service provider, not just the customers' local gas utility.

Driven by the success of unbundling the procurement function from other utility services, stakeholders pushed for further unbundling, including storage services and pipeline capacity reservations (both in-state and outside California). Unfortunately, the latter efforts have proceeded with mixed results.

Since the PG&E Gas Accord Settlement was adopted, customers in Northern California have had the ability to reserve long-distance pipeline transmission capacity specific to a particular location. SoCalGas, on the other hand, has not offered such specificity, only allowing customers to reserve capacity in its system. In that case, any oversubscription of capacity at a particular location may result in a pro rata reduction in capacity reserved for particular customers. Hence, SoCalGas cannot offer firm trading rights to its customers, reducing the value of the "unbundled" capacity rights that it might otherwise offer.

Ultimately, effective utilization of the natural gas system from a customer and utility perspective depends on the consistent application of rules and regulations statewide. California currently lacks this consistency, and this inconsistency needs to be resolved.

Reducing Natural Gas Dependence

With demand for natural gas increasing to meet the needs of a growing electricity generation market, concerns have emerged among state policy makers about California's increasing dependence on natural gas. These concerns have become even more pronounced with increased price volatility. The risks associated with long-run increases in the price of natural gas and supply shortfalls can be mitigated by reducing demand for natural gas for power generation. The effective implementation of the RPS and expanded energy efficiency programs are the critical element of reducing the state's dependence on natural gas.

Despite its support of renewable energy, California depends increasingly on natural gas generation, and natural gas-fired generation in California is expected to increase from 36 percent in 2004 to 43 percent in 2013.[35] The reductions in available hydroelectricity will push this percentage even higher. If California accelerates its use of renewable generation and meets the RPS goal of 20 percent by the year 2010 instead of 2017, and continues funding energy efficiency and DSM at present levels, the state can double the natural gas savings that come from displacing natural gas-fired generation by 2013.

Using other fuels can also reduce the demand for natural gas facilities. Nuclear, large hydroelectric, residual fuel oil, and coal facilities are unlikely candidates for offsetting natural gas-fired generation for California for a host of legal, environmental, and cost reasons. On the other hand, the development of cost-effective renewable resources (wind, geothermal, biomass, and solar) have tremendous potential in California to meet part of our future demand.

Natural Gas Infrastructure

California is located at the western end of a complex network of pipelines that spans the United States and Canada. While California has managed its own natural gas demand growth, supply sources, and infrastructure reasonably well, it is nonetheless greatly affected by supply/demand imbalances that occur in other regions, particularly with respect to infrastructure constraints that impede natural gas deliverability. Given the strong growth in natural gas demand in Nevada, Arizona, and the Pacific Northwest, it is paramount that California continues to:

1) develop additional interstate pipeline capacity from Canada, the South west, and the Rocky Mountains,

2) develop operational flexibility to utilize its in-state storage,

3) develop in-state productive capacity, and

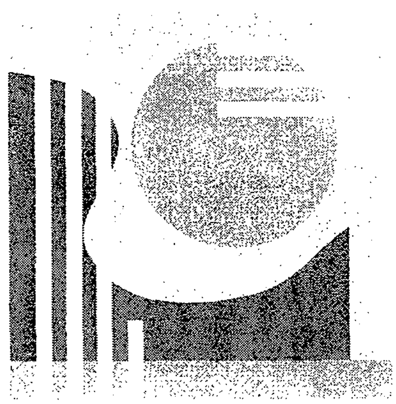
4) develop non-traditional supply sources such as liquefied natural gas (LNG).

Since the energy crisis, the state has increased access to out-of-state production through expansions of key interstate pipelines delivering gas from the Southwest, Canada, and the Rocky Mountains. The Federal Energy Regulatory Commission (FERC) has approved, on an expedited basis, additional interstate pipelines that now bring additional supplies to California. Under the watchful eye of the Natural Gas Working Group and CPUC oversight, SoCalGas and PG&E have expanded their pipeline capacities to receive more out-of-state supplies and enhanced the operational flexibility of their pipeline systems.

[35] California Energy Commission, *Electricity Infrastructure Assessment*, California Energy Commission, May 2003, Sacramento, CA, P100-03-007F.

Need for Effective Storage

Effective utilization of storage is critical to maximizing the operational flexibility of the natural gas system in California and reducing the need to add infrastructure. California presently has more than 240 billion cubic feet (Bcf) of storage capacity available with the ability to remove more than 5 Bcf per day on a peak winter day.[36]



Increases in storage capacity and withdrawal capability in both northern and southern California are important to meeting the growing energy needs of California gas customers. Equally important is the need to create a regulatory framework that encourages the effective use of storage throughout the state. Unfortunately, the existing tariff structure allows customers to reserve storage capacity but not necessarily fill it. This raises the likelihood that storage capacity will not be fully utilized, resulting in not enough gas being injected into storage during the storage injection season. Suboptimal use of storage leads to higher gas prices.

A result of the energy crisis, the CPUC authorized the utilities to increase natural gas storage capacity, including increased withdrawal and injection capabilities for existing utility storage and the addition of new non-utility storage facilities. As important as these improvements are to enhance capability of the state's natural gas system, further improvements will be necessary during the next decade.

Recognizing the Role of California Natural Gas Production

California gas producers play an important role in meeting the needs of natural gas consumers. As mentioned earlier, these producers satisfy approximately 15 percent of statewide natural gas demand. Stakeholders representing a number of producers suggested that this share could easily be maintained or even grow further if some of the various economic and regulatory disincentives are removed. Some of these disincentives include but are not limited to the following:

- Restricted access to utility gas gathering systems
- Lack of a streamlined permitting process for wellhead and production facilities
- Strict utility enforcement of gas quality specifications, with little opportunity to blend low Btu-quality gas with higher Btu-quality gas
- Limited access to land where natural gas deposits exist
- Absence of any rules enabling the effective testing of a new gas discovery[37]

[36] Ibid., *Electricity and Natural Gas Assessment Report*, California Energy Commission, October 2003, Sacramento, CA, P100-03-006D, p. 94.
[37] See written testimony of Joe Sparano (Western States Petroleum Association), dated August 29, 2003.

Some parties have suggested that the state should provide regulatory and tax incentives to expedite drilling and exploration. Others have argued that California producers should have better access to California natural gas markets.[38]

As a starting point toward removing these barriers, the Energy Commission, in collaboration with the Department of Conservation's Division of Oil, Gas, and Geothermal Resources, is beginning to explore these issues through the formation of a regulatory working group to promote cooperation between state and federal regulatory agencies, gas producers, and other interested parties to help improve the permitting process for drilling natural gas wells.

While collaboration has been an effective tool to address many of the barriers affecting California gas production, the Energy Commission recognizes two specific areas where legislative input may be needed for resolution. For more than a year, the Natural Gas Working Group has unsuccessfully attempted to broker a solution between California producers looking to serve the compressed natural gas vehicle market and SoCalGas, which imposes strict gas-quality requirements on these customers. For more than a decade, producers in Northern California have not been able to reach a solution which would allow them effective access to PG&E's gas gathering system, despite the issuance of two key CPUC decisions outlining such a solution.[39]

The Energy Commission recommends that the appropriate legislative committees initiate hearings to explore these two issues in greater detail and determine whether additional legislative action will be required to resolve the issue. The Energy Commission stands ready to assist if this approach is utilized.

Liquified Natural Gas Development

There are growing concerns that natural gas production from existing basins is in decline and unable to keep pace with growing demand for natural gas in North America. Many public and private natural gas analysts now predict that North American gas production will decline in future years. It is also unclear whether the industry can provide enough infrastructure to find and extract new sources of supply as well as add enough pipeline capacity to match current and future natural gas demand. Therefore, there is considerable interest in further developing infrastructure for liquefied natural gas (LNG) in North America to supplement our current supply of natural gas.

The completion of one or more of the currently proposed LNG facilities on the West Coast could add in excess of 1 Bcf per day of additional supplies. More importantly, LNG provides an opportunity for California to access supply from other countries and continents that may help bring downward pressure on Canadian and U.S. gas prices. However, overdependence on a foreign supply source has to be an additional concern.

[38] See testimony of John Allen (Occidental Petroleum – Elk Hills) at Energy Commission Integrated Energy Policy Report Hearing, October 10, 2003.
[39] See CPUC Decisions 89-02-016 and 97-08-055.

In the past two years, a number of developers have shown interest in building LNG facilities on the West Coast, along the coast of both Mexico and California. There have been at least 10 projects proposed on- and off-shore along the West Coast during the past year.[40] However, financial backing is probably available to support construction of one or two projects. Given recent regulatory activity in Mexico, which includes approval of all necessary permits for one proposal, it appears likely that at least one project will be built along the Baja California coast. California could benefit economically from LNG infrastructure being provided in the state.[41]

LNG, however, does not come without issues that will need resolution before it enters any pipeline system on the West Coast. Some are concerned about the relative safety of LNG. Others are concerned that the relative heat content of delivered LNG, which far surpasses what is considered to be appropriate for the utility systems in California, makes it difficult to move the gas into California without significant treatment or blending. Others are concerned about the type of natural gas sales contracts that are needed to support these large investments.

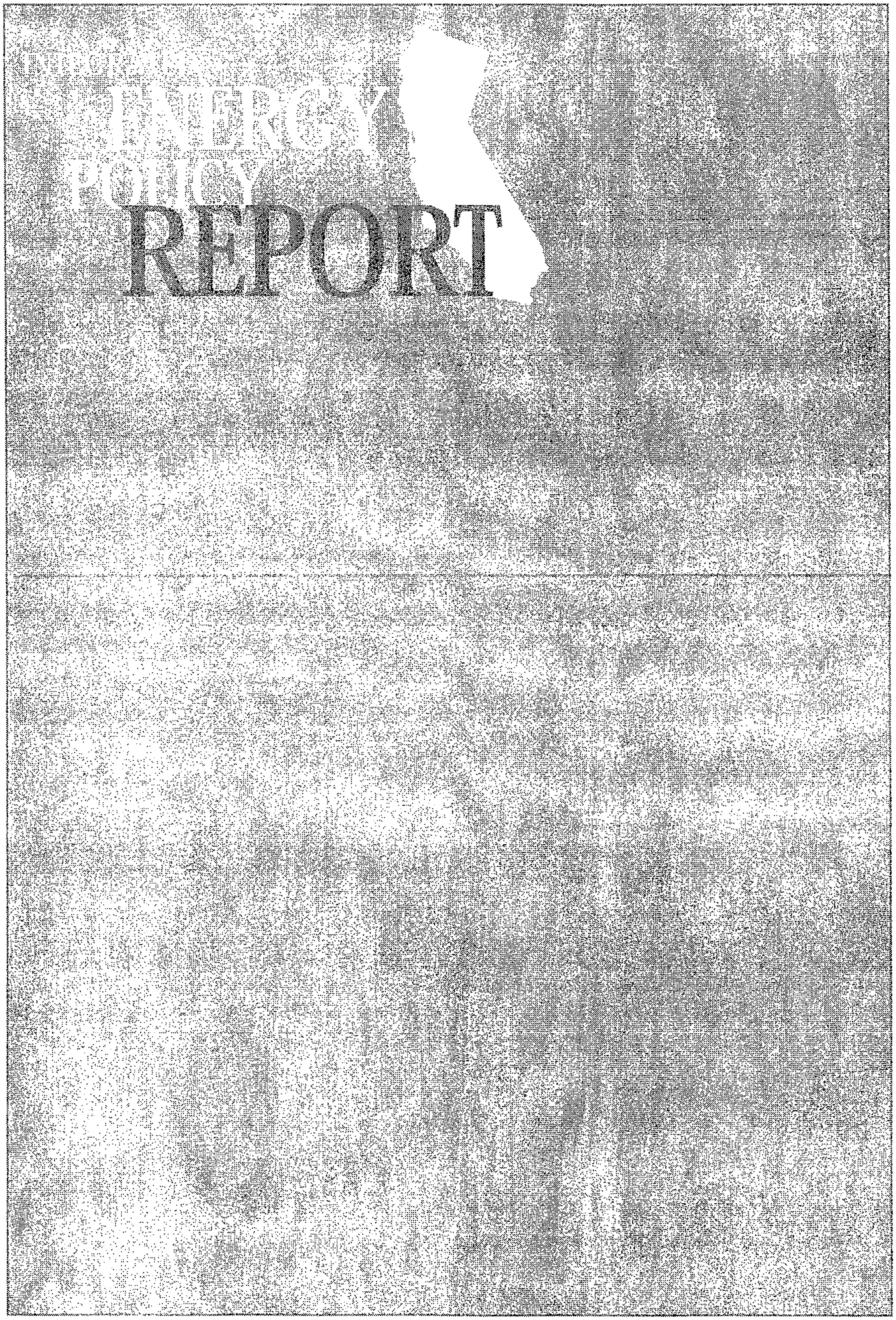
To address LNG issues more effectively at the state government level, the Energy Commission recently sponsored the formation of the LNG Interagency Permitting Working Group. The group meets on a regular basis and includes 13 public agencies potentially involved with permitting any potential LNG facility in California. The goal of the group is to ensure that any LNG development is consistent with state energy policy that balances environmental protection, public safety, and local community concerns.

Recommendations for Improving Natural Gas Infrastructure

The state should:

- Encourage the construction of LNG facilities and infrastructure and coordinate permit reviews with all entities to facilitate LNG facilities and infrastructure development on the West Coast.
- Ensure that existing natural gas storage capacity is appropriately used to provide adequate supplies and to protect prices.
- Initiate legislative hearings that will:
  1) examine the issue of gas quality and gas gathering as it relates to California gas production and
  2) determine whether additional legislative action is warranted to resolve the issues.

[40] California Energy Commission, "Pending Natural Gas Infrastructure Projects," [http://www.energy.ca.gov/naturalgas/documents/PENDING_PROJECTS.PDF].
[41] See testimony of Gene Voiland (AERA Energy) at Energy Commission Hearing, October 10, 2003.


ENERGY
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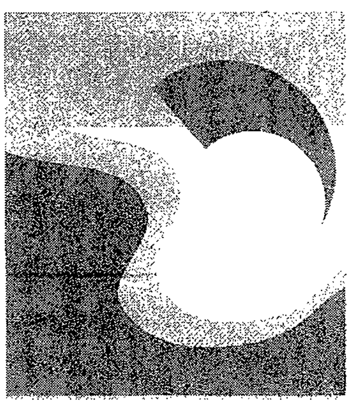
REPORT

SECTION FOUR Transportation Energy

The demand for transportation fuels in California is increasing at an alarming rate, surpassing in-state refining capacity. California's refiners rely increasingly on imported petroleum products to meet demand, and these imports enter through ocean port facilities that are reaching maximum capacity. The industry must expand its import and storage facilities, otherwise supply constraints and price volatility will continue.



The inability of the petroleum industry to meet today's needs without substantial price volatility causes concern about its ability to meet the growing demand for gasoline and diesel in the future. Without assurances from the industry how they will meet growing demand, the state must take aggressive steps to safeguard consumers and the California economy against more severe supply disruptions and price volatility.

The Energy Commission and CARB have developed a strategy to reduce California's singular dependence on petroleum that relies primarily on raising new vehicle fuel economy standards, and to a lesser extent increasing the use of alternative fuels, and introducing advanced vehicle technology such as hybrid-electric and hydrogen fuel cell vehicles.[42] The Energy Commission is beginning to work with stakeholder groups to identify effective avenues to implement the strategy.

The petroleum industry supports cost-effective vehicle efficiency improvements and alternative fuels development. It cautions, however, that a goal to reduce long-term demand for petroleum may significantly create disincentives to infrastructure investments, such as import and storage facilities that must be made now. The state must, nevertheless, balance supply and price consequences of infrastructure constraints with the potential benefits of moderating our dependence on petroleum.

Recent Trends in Meeting California's Transportation Energy Needs

In just the past 20 years, the demand for gasoline and diesel has increased 53 percent.[43] Californians now consume nearly 49.5 million gallons of gasoline and diesel each day, accounting for almost half of all the fossil fuel energy consumed in the state each year.[44] Several factors explain the increase, including:

[42] California Energy Commission and California Air Resources Board, *Reducing California's Petroleum Dependence*, California Energy Commission, August 2003, Sacramento, CA, P600-03-005F.
[43] California Energy Commission, *Transportation Fuels, Technologies, and Infrastructure Assessment*, California Energy Commission, October 2003, Sacramento, CA, P100-03-013D, p. 7.
[44] California Energy Commission, *Forecasts of California Transportation Energy Demand, 2003-2023*, Staff Report, California Energy Commission, 2003, Sacramento, CA, P100-03-016.

- Population growth and an increase in the number of on-road vehicles
- Declining per-mile cost of gasoline
- Land-use patterns that place jobs and housing increasingly farther apart
- The shift in consumer preference to larger, less fuel efficient motor vehicles
- A lack of viable and cost-effective alternatives to petroleum fuels

Until recently, California refiners produced enough transportation fuels to meet in-state needs and export to neighboring states. However, while demand has grown considerably, refining capacity has not. The last refinery built in California was in 1969. Since then, several refineries have shut down, reducing statewide refining capacity by nearly 20 percent.[45]

In spite of their age, the industry has upgraded and modernized its refineries over the years in response to meet the state's very tough fuel specifications. These refineries are now some of the most advanced and produce the cleanest-burning fuels in the world. Most recently, the industry is making significant modifications to its terminal facilities in response to the Governor's ban on MTBE, and these $800 million in modifications have proceeded without disrupting fuel supplies.

Since the mid-1990s, refiners have been able to increase production of gasoline and diesel at existing facilities through process improvements, but not enough to keep pace with the steadily growing demand. As a consequence, California increasingly relies on imports of blending components and finished products from other states and countries to meet demand. Today, refiners import about four million gallons of gasoline and diesel each day, a tenuous situation given the limited number of out-of-state refineries currently producing California gasoline.[46]

Gasoline, diesel, and blending components must be imported by marine tanker because California is not connected by pipeline to refining centers in other states. The state's marine facilities—where imports are off-loaded, stored, and distributed—operate at or near capacity. Likewise, refineries in California operate near maximum capacity for much of the year. Since inventories represent only 18 days of supply on average[47] and replacement supplies can take up to eight weeks to reach marine terminals, an upset in the petroleum system can immediately translate into tight supplies and higher prices at the pump.

Furthermore, gasoline and diesel demand does not drop when prices spike, so even small shortfalls in supply can cause very significant price swings. Spurred by record prices for crude oil and refinery problems in California, the average price for gasoline spiked to a record level of $2.15 a gallon in March 2003.[48]

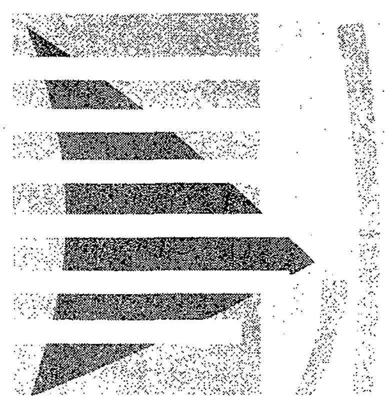
[45] California Energy Commission, 1981- 2003, *PIIRA Reports*, Operable capacity of nine reports.
[46] Ibid., p. 26.
[47] California Energy Commission, *California Strategic Fuels Reserve*, Revised Contract Report, California Energy Commission, July 2002, Sacramento, CA, P600-02-017D, p. 54.
[48] *Transportation Fuels, Technologies, and Infrastructure Assessment*, p. 36.

As California learned in August 2003, infrastructure problems in other states can seriously affect California. When an Arizona pipeline bringing gasoline supply from Texas recently ruptured, California refiners diverted supply to Arizona because California was the only nearby source of gasoline. When combined with several refinery outages on the West Coast, these events caused the average price of gasoline in California to reach $2.10 a gallon.[49]

Transportation Energy Outlook

Petroleum will be the primary source of California's transportation fuels for the foreseeable future. Over the next 20 years, the Energy Commission projects that gasoline and diesel demand for on-road vehicles will increase 36 percent and the demand for jet fuel will more than double.[50]

As demand continues to rise, imports of foreign crude oil will increase as in-state and Alaskan supplies diminish. Additionally, the transition to ethanol as the only oxygenate for California gasoline will reduce refinery production by as much as 5 percent.[51] Low-sulfur fuel regulations scheduled to take effect in 2006 also may further limit refining production. With refineries operating close to full capacity, daily imports of gasoline and diesel will more than double to 10.1 million gallons by 2010.[52] Unless import facilities expand, gasoline and diesel markets will become increasingly volatile, with the likelihood of supply shortages and more prolonged periods of high prices.



Improve Vehicle Efficiency

In almost every area of energy consumption, Californians have put efficiency first, but not transportation energy. The state's standards continually set new benchmarks for electricity and natural gas efficiency. California does not have similar authority for transportation, as it has for electricity and natural gas, and neglect at the federal level has allowed new vehicle fuel economy to decline in recent years. This is a cause of the significant increase in gasoline consumption.

In 1975, Congress established corporate average fuel economy (CAFE) standards for new passenger cars and light trucks. Since current CAFE standards, 27.5 miles per gallon for cars and 20.7 miles per gallon for light-trucks, including SUVs and minivans, have not changed since 1985, automobile manufacturers have not had the incentive to improve new vehicle fuel economy. Further, sales for light trucks have increased to nearly 50 percent of all new vehicles sold in California. These factors combined have contributed to the dramatic rise in gasoline demand.

[49] California Energy Commission, *Causes for Gasoline and Diesel Price Increases in California,* California Energy Commission, September Monthly Update, September 2003, Sacramento, CA, p. 4.
[50] *Forecasts of California Transportation Energy Demand, 2003-2023,* Staff Report.
[51] *Transportation Fuels, Technologies, and Infrastructure Assessment,* p. 28.
[52] Ibid., p. 26.

In its recent joint report, *Reducing California's Petroleum Dependence*, the Energy Commission and CARB examined a range of options to reduce petroleum consumption in California. In the near term, the state can quickly realize significant savings by establishing a tire efficiency program, requiring government fleets to use the most efficient vehicles in a given class, and educating consumers about proper vehicle maintenance. Together, these actions can reduce fuel demand by three to five percent, or about one-half billion gallons each year.[53]

The state has taken action on two of these measures. SB 844 [Chapter 645, Statutes of 2003, Nation] requires the Energy Commission to establish a tire testing procedure, a tire efficiency rating system, and replacement tire efficiency standards. The Department of General Services also is revising its vehicle procurement requirements to include efficiency as a primary criterion.

More importantly, the report showed that improving the fuel efficiency of new vehicles would dramatically reduce petroleum demand and that the efficiency of new cars and light trucks can be improved significantly with existing and emerging automotive technologies. If the combined fuel economy of new cars and light trucks were improved to 40 miles per gallon (mpg) beginning in the 2008 model year, the growth in demand for on-road transportation fuels would begin to decline by the year 2010 and continue to decline to current levels by 2020. This could save over 6 billion gallons per year.[54] For most of the efficiency options evaluated, fuel savings for consumers exceed the increased cost of a more fuel-efficient vehicle.

The federal government, through CAFE standards, has sole authority to require improvements in vehicle efficiency. California can only act in concert with other states and stakeholders to influence needed changes at the federal level. In the event the federal government fails to increase efficiency standards, the Energy Commission recommends that the state carefully reassess its strategy rather than immediately implement pricing measures or other fuel taxes and fees to lower demand.

Recommendations to Improve Vehicle Efficiency

The state should:

- Adopt a goal of reducing demand for on-road gasoline and diesel to 15 percent below 2003 levels by 2020 based on identified strategies that are achievable and cost-beneficial.
- Build a coalition with other states and stakeholders to influence Congress and the Department of Transportation to double the combined fuel economy of new passenger cars and light trucks by 2020. If the federal government fails to revise CAFE standards, California must reassess its petroleum reduction strategy.
- Develop a public information program to inform consumers of the fuel saving benefits of efficient tires, proper tire inflation, and vehicle maintenance.

[53] Ibid, p. 13
[54] California Energy Commission staff work, staff used the Futures Model to provide input to the *Reducing California's Petroleum Dependence.*

Diversify Transportation Fuels

California's demand for gasoline and diesel fuel is projected to increase by almost 35 percent over the next 20 years. Even though improving vehicle efficiency is the single most effective means to reduce petroleum dependence, the Energy Commission and the CARB have concluded that improving vehicle efficiency alone will not be enough to maintain petroleum reduction goals over the long-term. By 2020, the demand for gasoline and diesel will begin to increase once more as the number of vehicle miles traveled overwhelms efficiency benefits. For that reason, California must also increase our use of alternative fuels, including:

- Natural gas
- Ethanol
- Liquefied petroleum gas (LPG)
- Non-petroleum-derived diesel fuel such as Fischer-Tropsch and biodiesel
- Electricity
- Hydrogen

California is home to a growing number of alternative-fuel vehicles, through the efforts of the Energy Commission, CARB, local air districts, federal government, transit agencies, utilities, and other public and private entities. More than 60,000 cars, transit buses and trucks currently operate on natural gas and LPG, along with nearly 13,000 electric vehicles. California also has in excess of 800 natural gas and LPG fueling stations and is host to the California Fuel Cell Partnership.[55]

However, increasing the use of these fuels faces significant uncertainties such as the availability of new vehicle technologies, the cost and availability of new fueling infrastructures, and acceptance of these fuels by consumers. Given the recent supply and price volatility experienced in the natural gas market, California should proceed cautiously in creating a large natural gas demand for transportation.

Providing ethanol fuel for the existing fleet of flexible fuel vehicles currently on the road in California will help to diversify the state's market for transportation fuels. All U.S. automobile manufacturers currently build flexible fuel vehicles. California's fleet now includes an estimated 200,000 vehicles, yet because fueling infrastructure does not exist to supply ethanol, these vehicles use gasoline. At current rates, this fleet could grow to as many as 400,000 vehicles by 2010.[56]

[55] *Transportation Fuels, Technologies, and Infrastructure Assessment*, p. 63.
[56] California Energy Commission staff, Presentation: *California's Transition from MTBE to Ethanol and Beyond* at the U.S. Department of Energy and California Energy Commission sponsored "California Ethanol Workshop," April 14-15, 2003, Sacramento, CA.

Recommendation to Diversify Fuels

The state should:

- Increase the use of non-petroleum fuels to 20 percent of on-road fuel consumption by 2020 and 30 percent by 2030 based on identified strategies that are achievable and cost-beneficial.

Strengthen the Transportation Energy Infrastructure

California is importing increasing amounts of crude oil, blending components, and finished gasoline and diesel fuels to meet the state's growing demand. Yet the state's import facilities do not have the capacity to handle the increase flow of product effectively. The Energy Commission has conducted a preliminary study of the state's ability to import petroleum products and concluded that the infrastructure is at, or near, capacity.[57] The problems are most serious in Southern California, where the bulk of increased quantities of imported crude oil and finished petroleum products will be received.

Unless this infrastructure is expanded, refiners will not be able to meet demand with additional imports, which may increase price volatility. It is essential that additional marine and storage facilities are constructed and operating as the demand for transportation fuel increases.

The Energy Commission is planning a more comprehensive evaluation of the state's petroleum infrastructure including refineries, pipelines, ports, and storage facilities to identify product flows, pricing, and bottlenecks in the system and recommend solutions. An important component of this effort is the rulemaking already underway to expand and improve the process by which the industry must report to the Energy Commission information regarding petroleum product volumes and pricing. The Energy Commission expects this proceeding to be completed in early 2004.

A major barrier to expanding petroleum infrastructure is the difficulty in acquiring construction permits from multiple local, state, and federal authorities. These existing layers of permitting are inefficient and overlapping and contribute to the continuing shortage of storage capacity. This shortage leads to higher lease and rental rates for storage tanks. As a result, suppliers minimize their inventories, making for tighter markets and higher prices.

The state has successfully dealt with similar permitting problems. In 1974, to help license power plants, the Warren-Alquist Act, established the Energy Commission as a one-stop permitting agency. The Energy Commission's 12-month public process consolidates all state and local agencies into a single permitting process that meets the requirements of the CEQA and ensures that local concerns are balanced against statewide needs.

[57] California Energy Commission, *California Marine Petroleum Infrastructure*, Consultant Report, California Energy Commission, Sacramento, CA, P600-03-008.

Recommendation for Transportation Energy Infrastructure

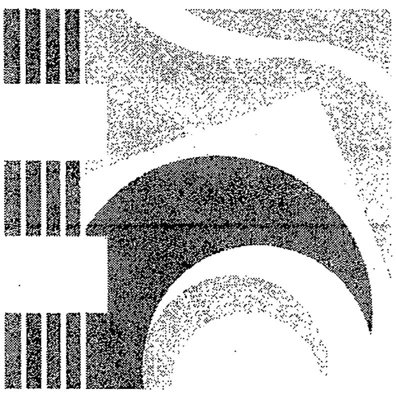
The state should:

- Establish a one-stop licensing process for petroleum infrastructure, including refineries, import and storage facilities, and pipelines that would expedite permits to increase supplies of transportation energy products available to California while maintaining environmental quality.

ENERGY POLICY REPORT

SECTION FIVE *Stewardship of California's Environment*

California's increasing need for energy places added pressure on the state's electricity, natural gas, and transportation fuel infrastructures as well as the state's environment. California must strike a balance between delivering increasing levels of energy and its commitment to environmental quality. The challenge to policy makers will be, not just to sustain the current status of the environment, but to improve environmental quality while meeting the wide-ranging demand for energy. This section addresses several topics where energy and the environment are inextricably linked and where clear policy direction is warranted.



Power Plant Water Use and Waste Water Discharge

Clean fresh water is an increasingly critical resource in California. California's burgeoning population, expected to grow from 35.5 million in 2003 to 47.5 million in 2020, combined with businesses and industry, will continue to use increasing quantities of fresh water at rates that cannot be sustained. Imbalances in available fresh water supply result in "average year" shortages projected in every region except parts of the San Francisco Bay area and the North Coast.[58] Energy facilities are among the state's many water users and have the potential to affect fresh water supply and water quality.

Since 1996, an increasing number of new power plants have been sited in areas with limited fresh water supplies. As a result, the use of fresh water for power plant cooling is increasing. Although water use for power plant cooling is relatively small on a statewide basis, it can cause significant impacts to local water supplies.

Degraded surface and groundwater can be reused for power plant cooling. When sufficient quantities are available, reclaimed water is a commercially viable cooling medium. Of the 8,409 MW of new cogeneration or combined cycle generated capacity permitted by the Energy Commission and brought on line in California between 1996 and September 2002, more than 1,580 MW or 19 percent is cooled using recycled water. Alternative cooling options, such as dry cooling, are also available and commercially viable, and can reduce or eliminate the need for fresh water. Two projects using dry or air cooling became operational in 1996 and 2001. A third project using dry cooling in San Diego County has been permitted by the Energy Commission.

[58] DWR, *The California Water Plan Update*, 1998, Bulletin 160-98, Volumes I and II.

Water quality impacts to surface water bodies, groundwater, and land from waste water discharges are increasingly controlled through technologies such as zero liquid discharge systems to meet the state's water quality standards. Of the 8,409 MW of new cogeneration or combined-cycle generating capacity, 16 percent used zero liquid discharge. More than 35 percent of the projects now under licensing review or under construction will use this technology.

Continued use of once-through cooling at existing power plants may impact aquatic resources in the coastal zone, bays, and estuaries. While power plants using once-through cooling have not been proposed for new California coastal sites in the last two decades, proposals to repower existing generation units at these sites have not switched to dry cooling or recycled water.

Water conservation is of paramount importance to the state. Indeed, conserving fresh water and avoiding its wasteful use have long been part of the state's water policy, as reflected in the State Constitution, Article X, Section 2. Because power plants have the potential to use substantial amounts of water for evaporative cooling, the Energy Commission has the responsibility to apply state water policy to minimize the use of fresh water, promote alternative cooling technologies, and minimize or avoid degradation of the quality of the state's water resources.

State water policy regarding power plants is specified in Resolution 75-58 adopted by the State Water Resources Control Board (the Board).[59] With respect to using fresh water, the Resolution articulates an underlying policy "to protect beneficial uses of the state's water resources and to keep the consumptive use of freshwater for power plant cooling to that minimally essential for the welfare of the citizens of the state."[60] The policy reflects the state's concerns over discharges from power plant cooling, as well as the conservation of fresh water for cooling purposes.

Specifically, the Board states that it "encourages ... power generating utilities and agencies to study the feasibility of using wastewater for power plant cooling" and "encourages the use of wastewater for power plant cooling where it is appropriate."[61] The Board also lists specific "discharge prohibitions" to limit the discharge of blowdown and waste waters from cooling facilities so as to "maintain existing water quality and aquatic environment of the state's water resources."

The Board further states as a matter of principle, "Where the Board has jurisdiction, use of fresh inland waters for power plant cooling will be approved by the Board only when it is demonstrated that the use of other water supply sources or other methods of cooling would be environmentally undesirable or economically unsound."[62]

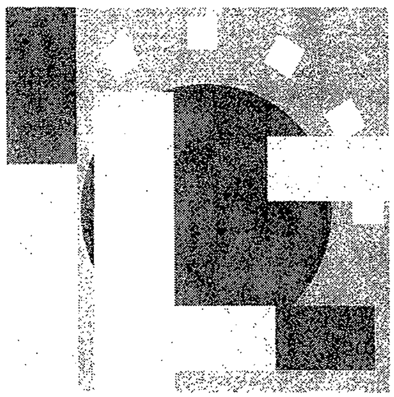
[59] Adopted in 1975, the Resolution is outdated in part in that it promotes once-through cooling with ocean water without regard to impacts to aquatic resources. Aquatic biological data collected in the last 28 years show that the biological harm caused by using ocean water for once-through cooling could be substantial. The adoption of 75-58 should be used to inform the Board in any decision on updating the Resolution.

[60] DWR, *Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling,* June 19, 1975, mimeo, p. 1.

[61] Ibid., p. 5.

[62] Ibid., p. 4.

The Warren-Alquist Act reiterates state water policy in terms of conserving water and using alternative sources of water supply:" It is further the policy of the state and the intent of the Legislature to promote all feasible means of energy and water conservation and all feasible uses of alternative energy and water supply sources." (emphasis added).[63]



Consistent with the Board policy and the Warren-Alquist Act, the Energy Commission will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative cooling technologies are shown to be "environmentally undesirable" or "economically unsound." Additionally, as a way to reduce the use of fresh water and to avoid discharges in keeping with the Board's policy, the Energy Commission will require zero-liquid discharge technologies unless such technologies are shown to be "environmentally undesirable" or "economically unsound." The Energy Commission interprets "environmentally undesirable" to mean the same as having a "significant adverse environmental impact" and "economically unsound" to mean the same as "economically or otherwise infeasible."[64]

Air Quality and Global Climate Change

Air pollution continues to produce major health impacts and poses a significant ecological threat in California. The majority of air emissions occur as energy and transportation fuels are stored, transported, and combusted. Air quality concerns and energy needs must be addressed concurrently; protecting the environment must be paramount.

California requires the cleanest-burning fuels and the most advanced combustion and pollution-reduction technologies. Future energy policies will need to both preserve and build upon past efforts to meet energy needs while assuring progress in reducing air pollution.

Climate change also represents a significant risk to California. The signs of a global climate change trend are becoming more evident and much of the scientific debate is now focused on expected rates of future changes. Rising temperatures and sea levels, along with changes in hydrological systems, are threats to California's economy, public health, and environment. Although these changes are not entirely predictable, climate change could lead to flooding of coastal communities, drought on our farmlands, disease and fires in our forests, decline of fish populations, reduced capacity to generate hydropower, and loss of habitat. Preliminary research suggests that annual residential and commercial energy expenditures in California alone could increase by as much as $2 billion by 2020 as a result of warmer climatic conditions.[65]

[63] Public Resources Code Section 25008.
[64] "Feasible" is defined under the CEQA as meaning "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors." (Cal. Code Regs., tit. 14, § 15365.) The same definition exists in the Energy Commission's siting regulations. (See Cal. Code Regs., tit. 20, § 1702(e).)
[65] Electric Power Research Institute, *Global Climate Change and California: Potential Implications for Ecosystems, Health and the Environment*, Consultant Report, California Energy Commission, 2003, Sacramento, CA, P500-03-099F, Appendix XI, Tables 9 and 11.

California has been a leader in responding to climate change through its inventory activities, the establishment of the California Climate Action Registry, the myriad energy efficiency, renewable energy, and environmental research and development programs, and regulation of automotive greenhouse gas emissions. However, more must be done to prepare for an uncertain climate future and improve the resiliency of the state's economy. The Energy Commission identified a range of strategies in 1998, including a need to account for the environmental impacts associated with energy production, planning, and procurement.[66] Through the West Coast Climate Initiative, California and its neighbors can partner in a leadership role to address risks posed by climate change.

Recommendations for Global Climate Change

The state should:

- Require reporting of greenhouse gas emissions as a condition of state licensing of new electric generating facilities.
- Account for the cost of greenhouse gas emission reductions in utility resource procurement decisions.
- Use sustainable energy and environmental designs in all state buildings.
- Require all state agencies to incorporate climate change mitigation and adaptation strategies in planning and policy documents.

Cross-Border Issues

California's environment along its border with Mexico is affected by energy consumption across the border as well as by energy consumption in California. Mexico has experienced strong industrial growth in its border area, resulting in increasing air pollution. States along the United States/Mexico border are affected by the increased emissions from inefficient power plants and boilers, fueling facilities, highly polluting industrial facilities, and traffic congestion. Baja California presents both compelling energy challenges and business opportunities for California.

Recommendation for Cross-Border Issues

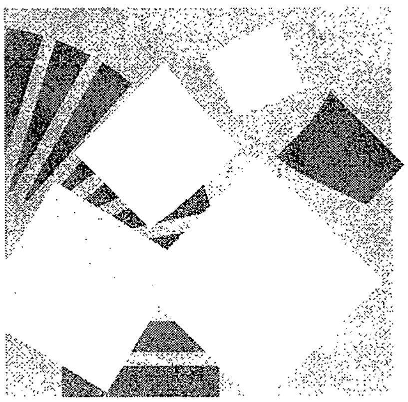
The state should:

- Conduct a Mexico Energy Program to fulfill joint declarations developed by the Border Governors' Commission Energy Worktable. The program should address energy and air quality issues on the California-Mexico border and stimulate energy technology exports for California energy companies.

[66] California Energy Commission, *1997 Global Climate Change, Greenhouse Gas Emissions Reduction Strategies for California, Volume 2*, Staff Report, California Energy Commission, 1998, Sacramento, CA, P500-98-001V2, p. 5.

Hydroelectricity Facility Relicensing

Hydroelectricity has historically played an important role in meeting California's electricity needs. Its low production costs and unique ability to meet critical peak demand have long benefited the state's ratepayers. Some hydroelectric projects unfortunately have serious environmental consequences such as significant, ongoing impacts to many California rivers and streams, native salmon and trout populations, and the water quality needed to support sustainable riverine ecosystems.



The restoration of imperiled salmon and trout fisheries is one of California's environmental policy objectives. Since the FERC licensed most of the state's hydroelectric facilities more than 30 years ago, these facilities were not subject to current environmental standards. By 2015, 44 FERC-licensed projects in California will seek renewals, affording the state the rare opportunity to address problems with existing fisheries and aquatic resources. In addition, decommissioning of high environmental impact hydroelectric facilities that supply little power is a possible method of restoring important aquatic habitat.

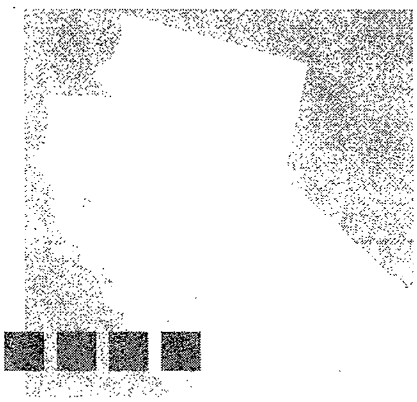
California's Department of Fish and Game and the State Water Resources Control Board both have principal roles as the state's representatives in FERC's re-licensing of hydroelectric facilities. The Energy Commission is helping these agencies and FERC understand the effects that operational and structural changes to these facilities will have on regional and statewide electricity supply.

INTEGRATED ENERGY POLICY REPORT

SECTION SIX *Conclusion*

In three short years, California has weathered an electricity crisis, unparalleled natural gas price spikes, and the highest gasoline prices in the nation.

As the fifth largest economy in the world, energy is a vital concern to California. Through crises, error, and innovation, California remains a world leader in energy policy and technology. What begins in California eventually moves throughout the world.



Since the 1970s, California has responded to each energy challenge by developing efficiency programs, promoting new forms of renewable energy, and fostering research and development. These efforts have pushed the boundaries of regulation and private investment.

California's growing population demands reliable and reasonably priced energy. Yet today, California finds itself facing an aging energy infrastructure and ever-growing demand.

The state rightfully feels a sense of urgency. Finding the most cost-effective, reliable, efficient resources, while protecting our environment, calls for more than a "business- as-usual" approach. If California's energy future is to remain economically workable and environmentally sound, progressive energy policy must remain high on the state's agenda.

The recommendations described in this report represent an aggressive, wide ranging agenda for decision makers, businesses, and individuals. The Energy Commission believes that this report, along with its subsidiary volumes, lays the proper foundation for future action.

INTEGRATED
ENERGY POLICY REPORT

ACKNOWLEDGEMENTS

The Integrated Energy Policy Report represents the culmination of an extensive process of hearings, comments, and analysis. Along with the Energy Commission staff, numerous public agencies, private energy and energy-related companies, and public interest groups have provided invaluable comments and critiques of the technical analyses and policy recommendations. The final report reflects this broad range of experience and viewpoints. In particular, the Energy Commission gratefully acknowledges the following:

Government Organizations

Bay Area Air Quality Management District
California Air Resources Board
California Department of Transportation
California Independent System Operator
California Public Utilities Commission
City of San Diego
Consumer Power & Conservation Financing Authority
Electricity Oversight Board

Private Entities

AERA Energy, LLC
Alliance for Retail Energy Markets
Bay Area Economic Forum
Berry Petroleum Company
Border Power Plant Working Group
California Chamber of Commerce
California Cogeneration Council
California Manufacturers and Technology Association
Cal-Tax
Central Labor Council of Alameda County
Coldwell Banker
David L. Richter
DeMaria Electric Motor Services, Inc.
DeWitt Petroleum
Duke Energy North America
Dynegy, Inc.
Eco Securities
Energy Efficient Mortgage
Golden State Power Cooperative
Gray Panthers of the San Fernando Valley
Independent Energy Producers Association
Independent Oil Producers Agency
K.J. Kammerer & Associates
Kern River Cogeneration Company
Law Offices of Daniel W. Douglass
National Biodiesel Board

***Private Entities** (continued)*

Natural Resources Defense Council
Ninyo & Moore
NRG Energy
Oak Creek Energy Systems, Inc.
Occidental Petroleum Corporation
Pacific Gas and Electric Company
Reliant Energy
San Diego Gas and Electric Company
Sempra Energy Global Enterprises
Sharon Lanini, Agricultural Consultant
Shell Trading Gas and Power Company
Silicon Valley Manufacturing Group
Southern California Edison Company
Sustainable Energy Development
The Southern California Gas Company
TIMEC
Utility Consumers' Action Network
Watson Cogeneration Company
West Coast Power
Western States Petroleum Association
Women's Energy Matters

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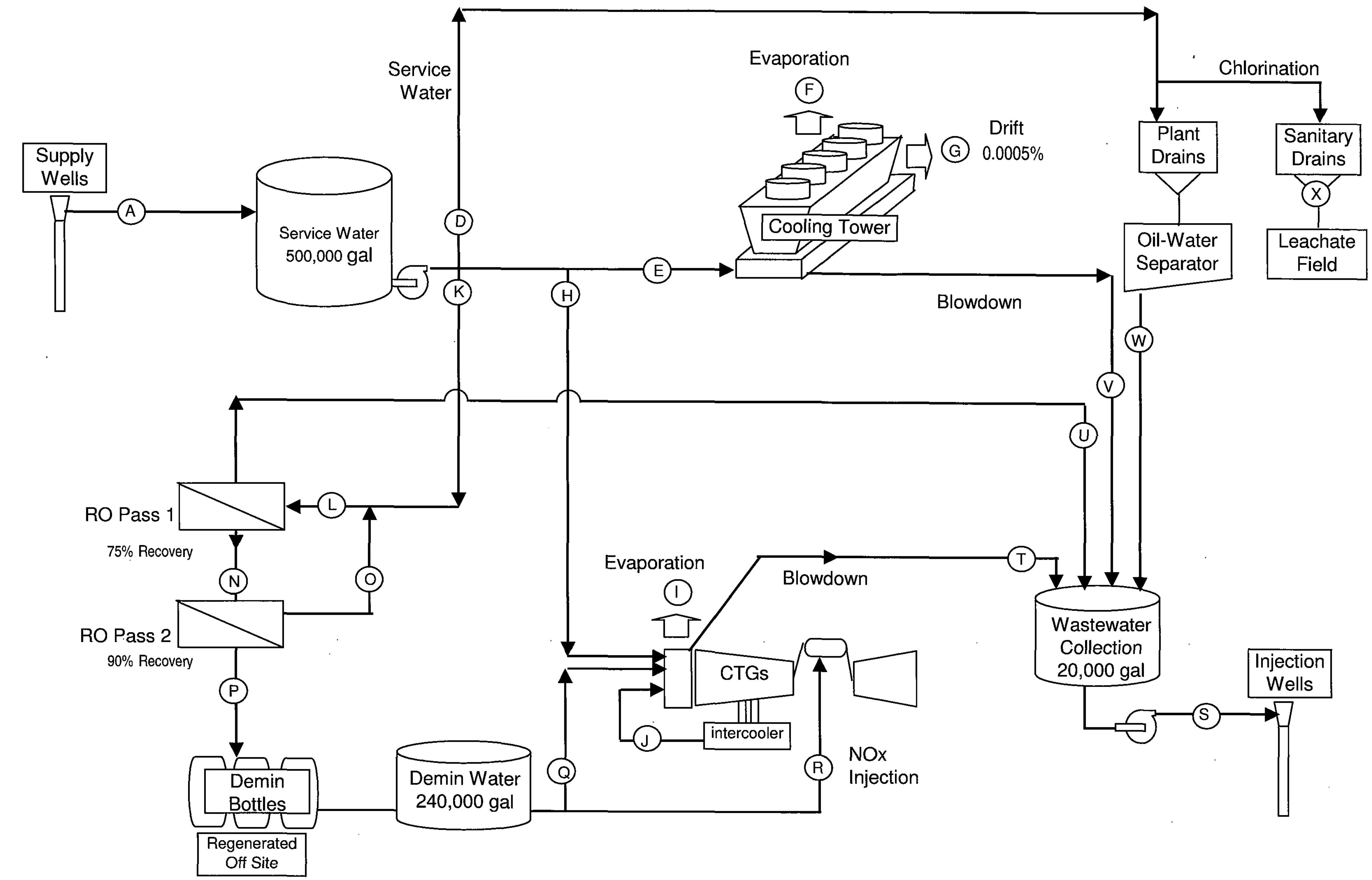

D	Revised Format	REB	BMC	SMG	7/27/07
C	Increased CT COC, added chart	REB	CF	SMG	2/16/07
B	Revised Evap COC & Added Fig	DNL	REB	SMG	7/21/06
A	Issued for AFC Permit	DNL	REB	SMG	6/21/06
Rev	DESCRIPTION	Dwn	Chk	App	Date

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8455 Lenexa Drive
Lenexa, Kansas 66214

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Drawn	DNL	6/21/06	
Checked	REB	6/21/06	2006-027-WB-001-1
Approved	SMG	6/21/06	

EXHIBIT 33 (2 pages)

	Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Case ID	Peak hr	Peak night	Peak 24 hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
	Ambient Temperature	114	80	97	48	51	57	61	70	72	82	81	77	66	54	47	64
	Wet Bulb Temperature	74	64	69	45	47	51	52	57	62	65	65	62	56	49	43	55
	Relative Humidity	14.6	41.8	28.2	81.0	74.8	64.9	53.9	44.6	55.9	39.5	42.4	43.8	52.3	70.7	75.5	58.3
	Ambient Pressure	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500	14.500
	Inlet Air Cooler Status	On	On	On	Off	Off	Off	Off	On	On	On	On	On	Off	Off	Off	N/A
	Number of CTs in service	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Hours per Year	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Description																
A	Flow from the supply wells	1486.0	1220.6	1353.3	984.8	1011.3	1064.7	1095.0	1171.3	1183.5	1234.8	1223.9	1195.3	1118.0	1038.4	984.5	1108.8
D	Service water to washdown	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
E	Service water to cooling tower	1110.0	844.9	977.5	623.9	649.6	702.1	728.5	776.4	812.6	863.5	856.9	810.2	761.0	676.8	621.5	740.2
F	Cooling Tower Evaporation	887.9	675.8	781.9	499.0	519.6	561.6	582.7	621.0	650.0	690.7	685.4	648.0	608.7	541.4	497.1	592.1
G	Cooling Tower Drift	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
H	Service water to evap coolers	17.2	12.3	14.7	0.0	0.0	0.0	0.0	12.7	9.9	11.6	10.5	14.1	0.0	0.0	0.0	4.9
I	Evap cooler evaporation	91.0	38.0	64.5	0.0	0.0	0.0	0.0	31.6	24.8	40.9	38.2	35.1	0.0	0.0	0.0	14.2
J	Intercooler condensation	57.6	8.6	33.1	0.0	0.0	0.0	0.0	0.0	0.0	14.4	14.4	0.0	0.0	0.0	0.0	2.4
K	Service Water to RO System	353.5	358.1	355.8	355.6	356.4	357.3	361.3	376.9	355.7	354.4	351.3	365.9	351.8	356.3	357.8	358.4
L	RO Pass 1 Inlet Flow	382.2	387.2	384.7	384.4	385.3	386.3	390.6	407.5	384.5	383.2	379.8	395.5	380.3	385.2	386.8	387.4
N	RO Pass 2 Inlet Flow	286.6	290.4	288.5	288.3	289.0	289.7	292.9	305.6	288.4	287.4	284.8	296.6	285.2	288.9	290.1	290.6
O	RO Pass 2 Reject to Pass 1	28.7	29.0	28.9	28.8	28.9	29.0	29.3	30.6	28.8	28.7	28.5	29.7	28.5	28.9	29.0	29.1
P	Total Demineralized water	258.0	261.3	259.7	259.5	260.1	260.8	263.6	275.1	259.5	258.6	256.3	267.0	256.7	260.0	261.1	261.5
Q	Demin water to evap coolers	34.4	24.6	29.5	0.0	0.0	0.0	0.0	25.3	19.9	23.1	20.9	28.1	0.0	0.0	0.0	9.8
R	NOx injection	223.6	236.7	230.2	259.5	260.1	260.8	263.6	249.7	239.7	235.5	235.4	238.9	256.7	260.0	261.1	251.7
S	Wastewater to Injection Well	340.7	278.3	309.5	225.9	231.2	242.0	248.3	268.5	268.6	281.6	278.9	272.9	252.2	236.6	226.0	252.7
T	Evaporative cooler blowdown	18.2	7.6	12.9	0.0	0.0	0.0	0.0	6.3	5.0	8.2	7.6	7.0	0.0	0.0	0.0	2.8
U	RO rejects	95.5	96.8	96.2	96.1	96.3	96.6	97.6	101.9	96.1	95.8	94.9	98.9	95.1	96.3	96.7	96.9
V	Cooling Tower Blowdown	222.0	169.0	195.5	124.8	129.9	140.4	145.7	155.3	162.5	172.7	171.3	162.0	152.2	135.3	124.3	148.0
W	Plant Drains	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
X	Sanitary Drains	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

Notes:

1) All Flows are displayed in GPM
2) Based on GE performance estimates
3) Reverse Osmosis 1st Pass Recovery Rate 75%
4) Reverse Osmosis 2nd Pass Recovery Rate 90%
5) Cooling Tower Drift 0.0005%
6) Cooling Tower cycles of concentration 5.0
7) Evap Cooler cycles of concentration 6.0
8) Evap Cooler demin water split 67%
10) Sanitary water flows based on:
    Gallons per day per person 25
    People on site 15

Annual Flows:		Annual	Q1	Q2	Q3	Q4
Annual Capacity Factor		57%				
Hours of Operation		5,000	1,100	1,100	1,600	1,200
Water Use	Acre-ft	1,030	207	233	359	231
	1000 gal	335,539	67,336	75,895	116,927	75,382
Water Disposal	Acre-ft	235	47	53	82	53
	1000 gal	76,484	15,379	17,278	26,671	17,156

Daily Flows:			
Peak Day			Peak Day is based on an average
Water Use	1000 gal/day	1,949	of the flows at the record high temp
Water Disposal	1000 gal/day	446	and an assumed night time low of
Average Day			Average day is based on the
Water Use	1000 gal/day	1,342	annual flow and an estimated 250
Water Disposal	1000 gal/day	306	days of plant operation

Rev	DESCRIPTION	Dwn	Chk	App	Date
D	Revised Format	REB	BMC	SMG	7/27/07
C	Increased CT COC, added chart	REB	CF	SMG	2/16/07
B	Revised Evap COC & Added Fig N	DNL	REB	SMG	7/21/06
A	Issued for AFC Permit	DNL	REB	SMG	6/21/06

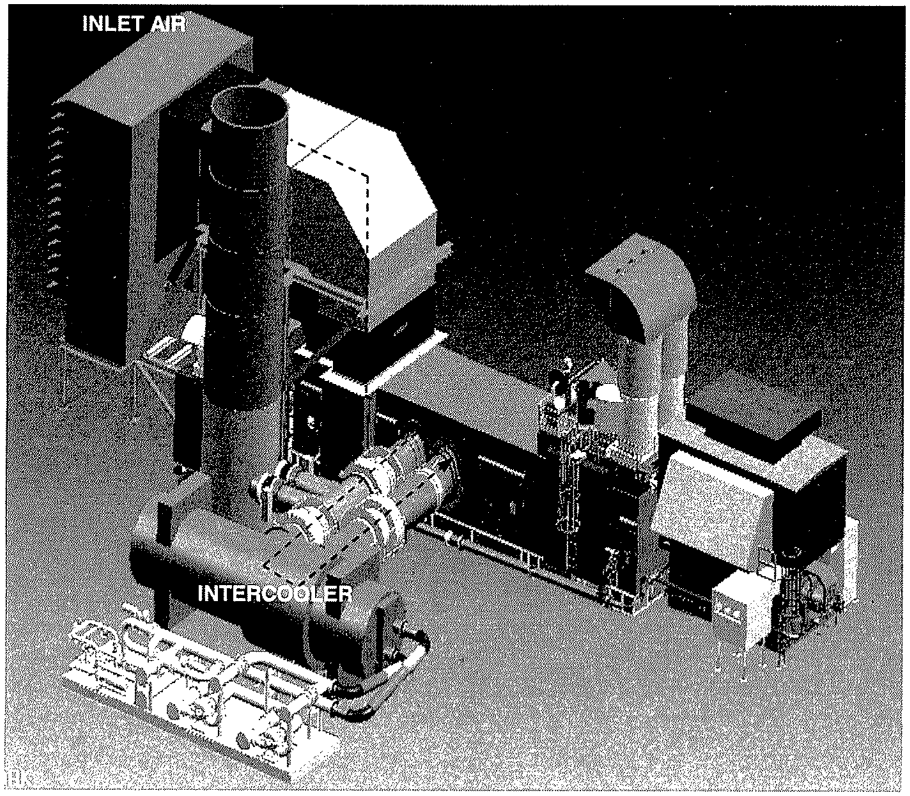
PANOCHE ENERGY CENTER, LLC

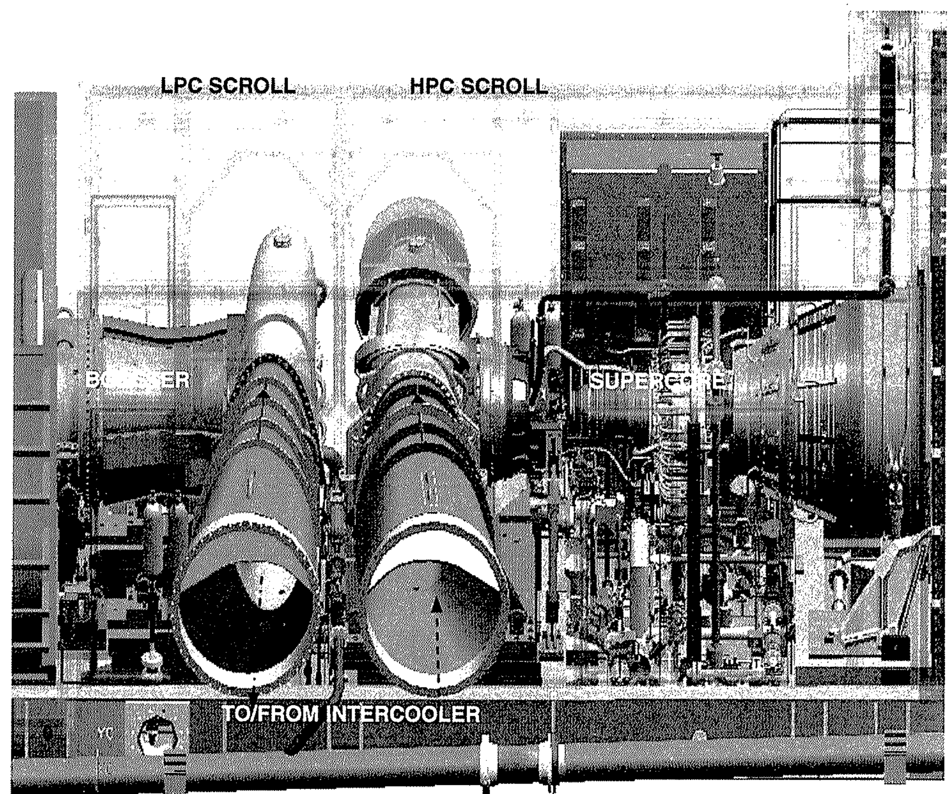
Bibb and associates
8455 Lenexa Drive
Lenexa, Kansas 66214

WATER BALANCE - LOWER AQUIFER

	by	date	DRAWING NUMBER
Drawn	DNL	6/21/06	
Checked	REB	6/21/06	2006-027-WB-001-2
Approved	SMG	6/21/06	

EXHIBIT 34

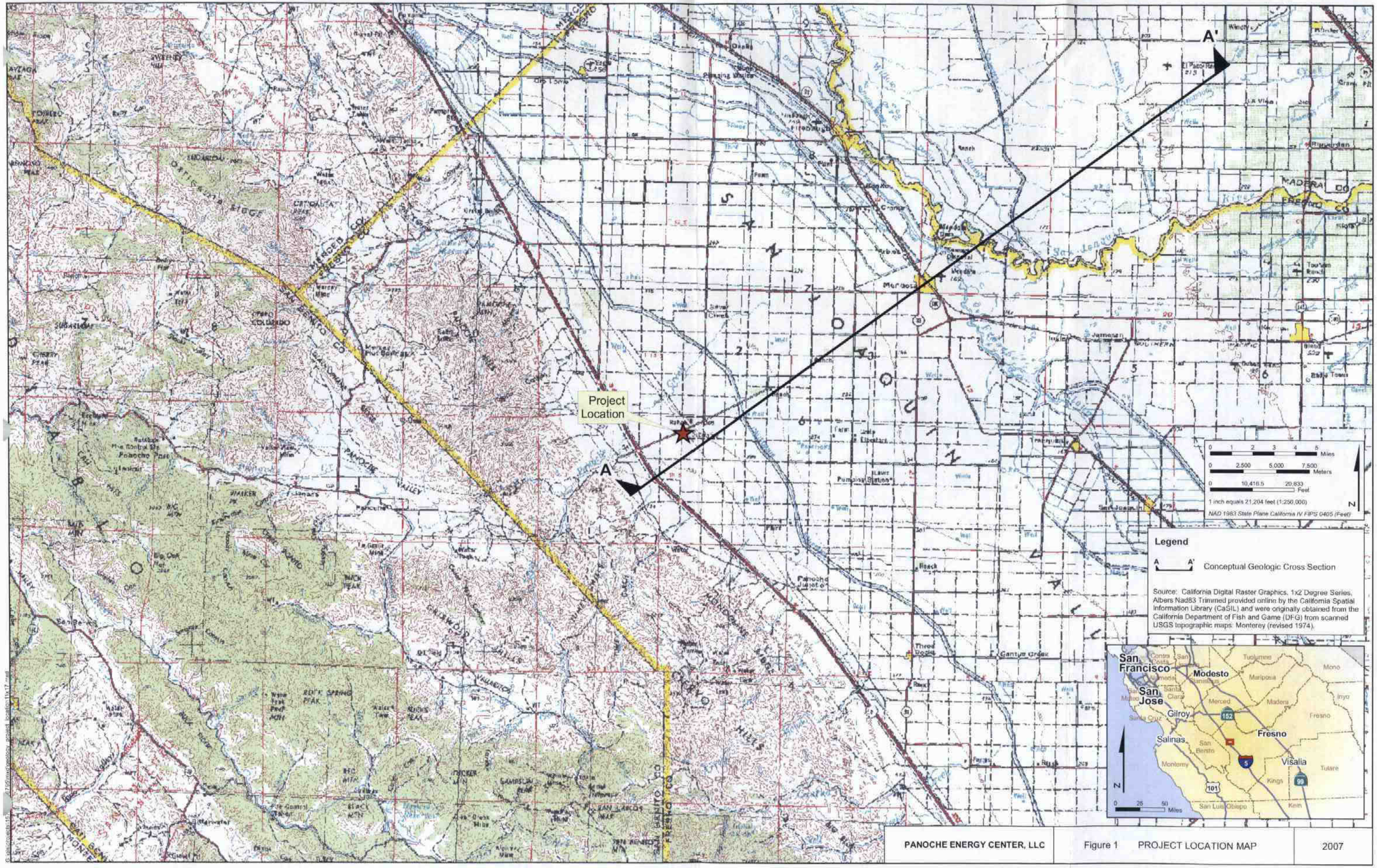

INLET AIR
INTERCOOLER


LPC SCROLL
HPC SCROLL
TO/FROM INTERCOOLER

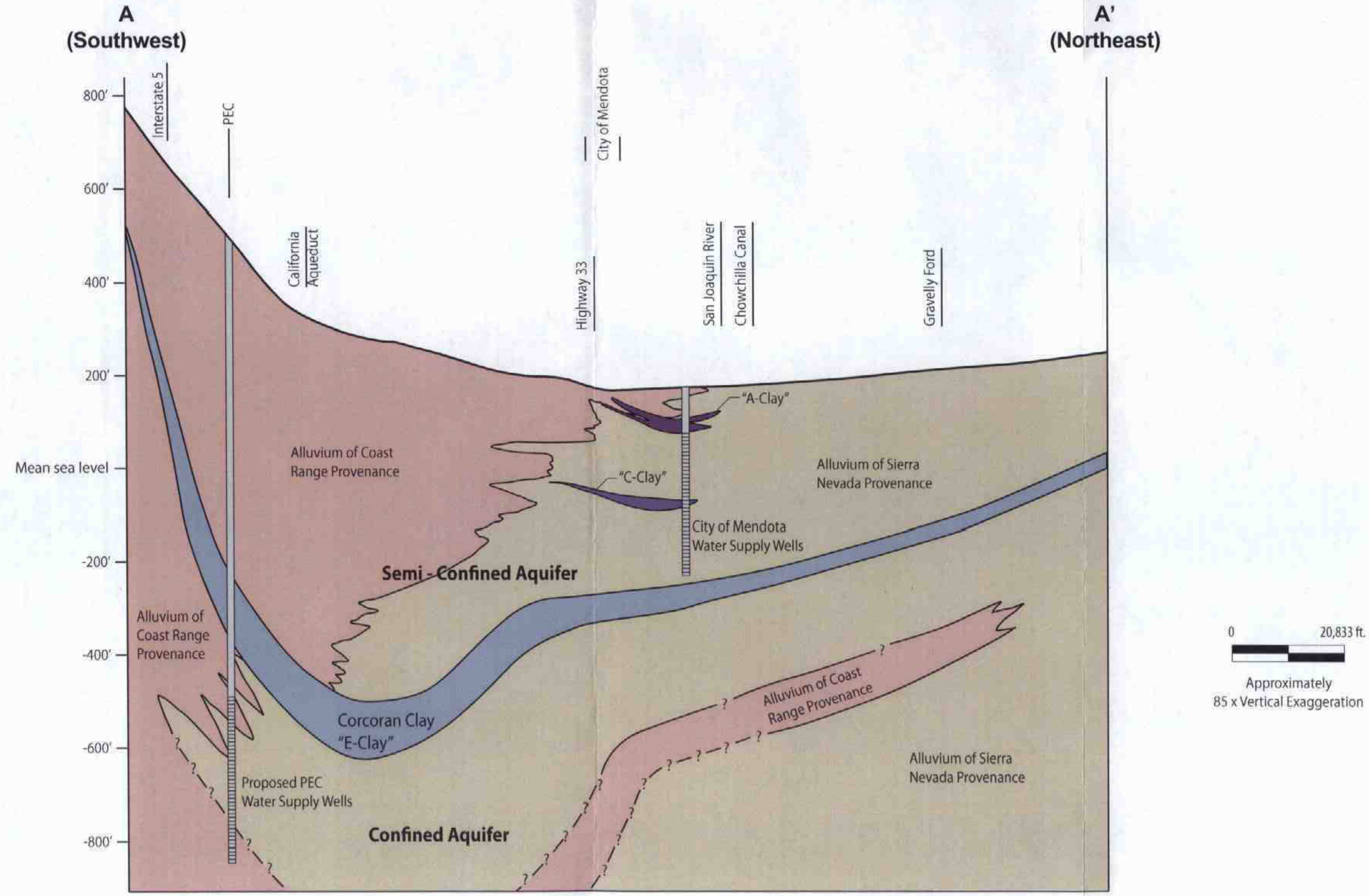
Panoche Energy Center
Engineering Estimate - Lime & Soda Ash Softening System
Bibb Project Number: 2006-027
Prepared By: SMG
Checked By: JDS
File No: 010A
Date: August 15, 2007

Item	Description	Estimated Cost
1	Lime Softening Clarifier System	$2,500,000
2	SCU	Included
3	Lime Silo	Included
4	Soda Ash Silo	Included
5	Clearwell	Included
6	Pumps	Included
7	Thickener	Included
8	Filter press	Included
9	Controls	Included
10	Multi-Media Filter & Reverse Osmosis System	$2,100,000
11	Multi media filters (2)	Included
12	Reverse Osmosis System (2)	Included
13	Membrane CIP skid	Included
14	Controls	Included
15	Building	$600,000
16	Installation (foundations, piping, electrical)	$4,600,000
17	Storage Tank, 2 million gallons	$2,500,000
18	Subtotal	$12,300,000
19	Engineering	$1,230,000
20	Contingency, Overhead, and Profit	$4,060,000
21	Total	$17,590,000

EXHIBIT 35



PANOCHE ENERGY CENTER, LLC	Figure 1 PROJECT LOCATION MAP	2007



NOTE:
Geology and hydrogeology based on interpretation of available data. Contacts shown as solid lines for clarity and are not intended to imply certainty.

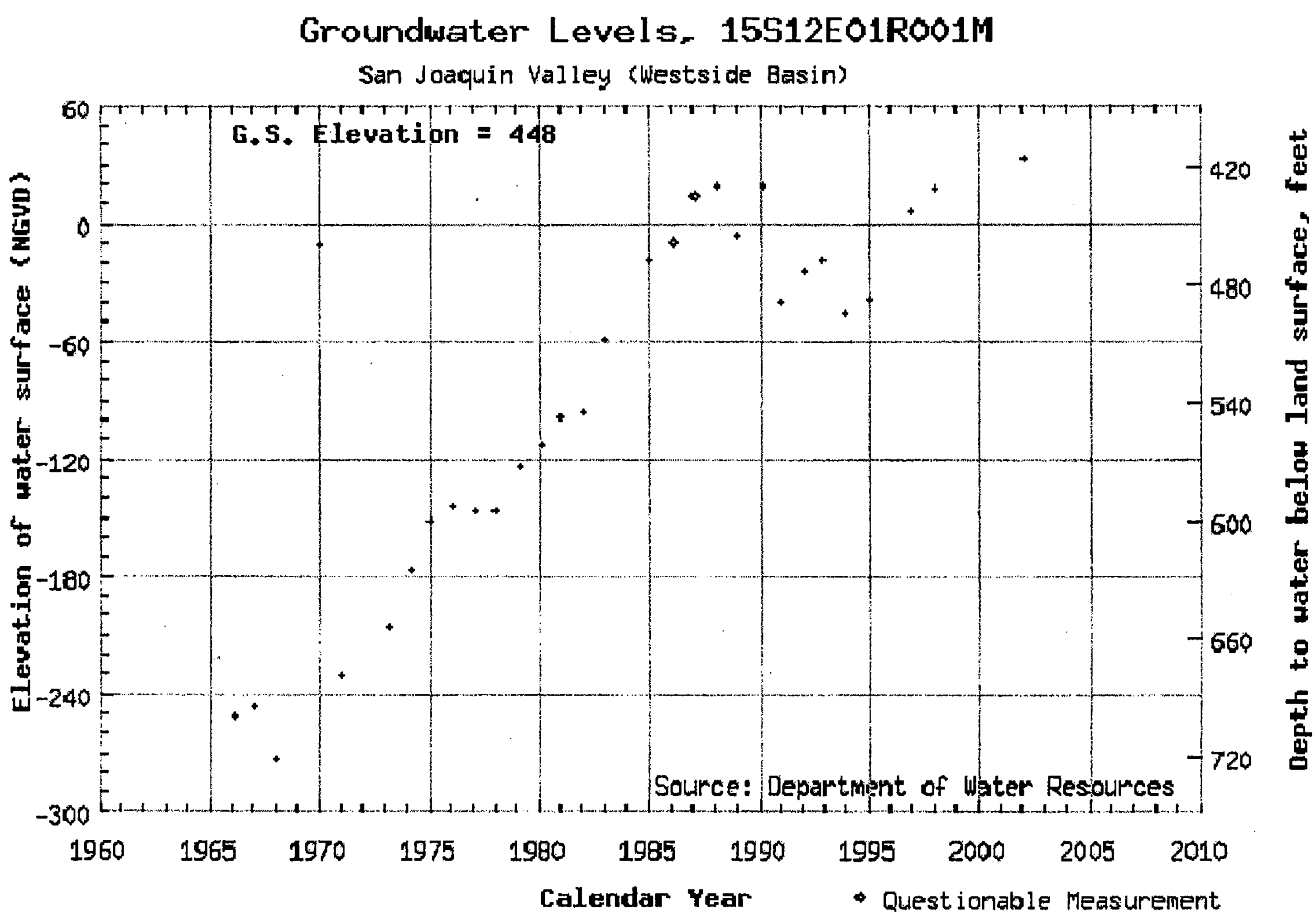
URS

Conceptual
Geologic Cross-Section A-A'

Panoche Energy Center

Figure 2

37



SOURSE: DEPARTMENT OF WATER RESOURCES
(wdl. water.ca.gov)

PANOCHE ENERGY CENTER, LLC	HYDROGRAPH FOR WELL 15S12E01R001M	FIGURE 3

38

MAGGIE FITZGERALD

Prepared Direct Testimony
Of
Maggie Fitzgerald
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Maggie Fitzgerald and I am employed by URS Corporation.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's environmental project management.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) Appendix Q, List of Property Owners

   Data Adequacy Response(s): BIO-5, LAND-7, LAND-9 WATER-27, WATER-33

   Data Request Response(s): LAND-39, LAND-40, SOIL-49

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

10-1-07
Date

Maggie Fitzgerald

JEFF FULLER

Prepared Direct Testimony
Of
Jeff Fuller
For
Panoche Energy Center Project

1. Q. Please state your name and place of employment
   A. My name is Jeff Fuller and I am employed by Kimley-Horn and Associates, Inc.

2. Q. What are your duties and responsibilities with regard to the Panoche Energy Center?
   A. I am responsible for analyzing the PEC's noise impacts.

3. Q. What material are you sponsoring in this proceeding?
   A. AFC Section(s) 5.12, Noise
   Appendix M, Noise Measurements

   Data Request Response(s): NOI-40

4. Q. Have you either prepared or reviewed the material that you are sponsoring?
   A. Yes.

5. Q. Would you please swear to the veracity of the material you are sponsoring?

   A. I hereby swear under penalty of perjury that the material contained in this document and the sponsored exhibits is true and correct to the best of my knowledge.

Oct 2, 2007
Date

Jeff Fuller

Kimley-Horn
and Associates, Inc.

Jeffrey D. Fuller, INCE, REHS

Professional Credentials

Bachelor of Science, Environmental Health, University of Washington, Seattle, 1981
Registered Environmental Health Specialist (REHS), California, #4628 (1981)
Approved Acoustical Consultant, County of San Diego
Member, Institute of Noise Control Engineering (INCE)
Member, FHWA Transportation and Research Board
Member, Acoustical Society of America
Former Member, City of San Diego Noise Abatement and Control Board

Special Qualifications

- Manager, URS Corporation, Noise and Vibration, San Diego, California , (1996-2005)
- Senior Acoustician, Ogden Environmental and Energy Services Company (1989-1996)
- Noise Abatement and Control Administrator, City of San Diego, Building Inspection Department, (1981-1989)

Introduction

Mr. Fuller is proficient in noise and vibration practices. He has more than 26 years of experience in acoustical assessments and project management. Jeff is responsible for project planning, directing and supervising staff professionals, and the coordination and preparation of noise and vibration technical studies and sections of environmental documents for agencies such as the Federal Energy Regulatory Commission (FERC) and the California Energy Commission (CEC). His responsibilities also include the assessment of impacts associated with commercial/industrial, transportation (airports, helipads, railroads, and highways), and residential and mixed-use development projects. His expertise with noise/land use compatibility is utilized regionally and nationally to provide innovative solutions to numerous client problems.

Jeff's technical capabilities include the use of computer-aided noise models to predict noise levels and to design and evaluate effective measures to mitigate noise impacts. Additionally, he frequently uses various sound level meters, dosimeters, and spectrum analyzers for conducting noise-monitoring surveys.

Relevant Experience

Panoche Energy Center, Panoche Energy Center, LLC, Fresno County, CA — Mr. Fuller prepared a noise analysis for an Application for Certification for a nominal 400-megawatt peaking facility consisting of four General Electric LMS100 natural gas-fired combustion turbine generators, emissions control equipment, one cooling tower, and process water treatment equipment and other associated equipment. The analysis addressed CEC and local noise requirements.

Niland Gas Turbine Plant, IID Energy, Niland CA — Mr. Fuller provided noise technical review and analysis for an Application for Small Power Plant Exemption (SPPE) to IID Energy and URS Corporation for the permitting of a nominal 93-megawatt simple-cycle power plant on a 160-acre site in Niland, California. In addition, Jeff provided testimony at the California Energy Commission Staff Workshop.

ECGS, IID Energy, El Centro, CA — Mr. Fuller provided noise technical review and analysis for an Application for Small Power Plant Exemption (SPPE) to IID Energy and URS Corporation for the construction and operation of the ECGS Unit 3 Repower Project. The project consisted of minor modifications to the existing Unit 3 cooling tower, replacement of the Unit 3 condenser, minor modifications to Unit 3 STG the 92kV electrical interconnection and modifications to the existing gas interconnection facilities.

AES Huntington Beach Generating Station Retool Project, AES, Huntington Beach, CA — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis for an Application for Certification retool Units 3 and 4. The proposed project will produce a nominal 450 MW. Jeff provided testimony before the California Energy Commission. The plant subsequently been approved to operate.

Potrero Power Plant, Mirant, San Francisco, CA — Prior to joining Kimley-Horn Mr. Fuller was Task Manager for an Application for Certification for the addition of a new 500-MW combined cycle unit (Unit 7) on the site of the existing Potrero plant. He prepared a noise analysis as part of the submittal. The AFC has subsequently been deemed "data adequate.

Contra Costa Power Plant, Mirant, Contra Costa County, CA — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis on behalf of SECAL for an Application for Certification to the California Energy Commission for a 500-MW combined cycle gas turbine plant on the site of the existing power plant. The plant subsequently has been approved to operate.

Three Mountain Power Plant, Burney California, Ogden Power, Burney, CA — Prior to joining Kimley-Horn Mr. Fuller was Task Manager for an Application for Certification. Mr. Fuller prepared a noise study for the addition of a 500-MW gas-fired power plant in Burney. In addition, he provided testimony to the California Energy Commission for the certification of the plant.

West Bend 1, Kansas City Power & Light Company, Kansas City, MO — Prior to joining Kimley-Horn Mr. Fuller prepared a draft noise analysis for the West Bend 1 Power Plant Project. The Proposed Action was to construct, operate, and maintain a nominal 750-megawatt (MW) coal-fired power plant and ancillary facilities.

Big Sandy Energy Project, Mohave County, AZ — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis for the Big Sandy Power Project. The Proposed Action was to construct, operate, and maintain a 720-megawatt natural gas-fired, combined-cycle power plant and ancillary facilities. The power plant would be interconnected to the regional electric transmission grid through an existing 500-kilovolt transmission line.

La Paz Power Plant Project, Allegheny Energy, La Paz County, AZ — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis for the La Paz Power Plant Project. The Proposed Action was to construct, operate, and maintain a nominal 500-megawatt natural gas-fired, combined-cycle power plant and ancillary facilities.

Power Plant Siting Noise Study, American National Power Company, Midlothian, TX — Prior to joining Kimley-Horn Mr. Fuller prepared a noise study, which assessed potential impacts associated with the siting of a power plant in Texas. Acoustical calculations were performed to estimate worst case sound levels at noise sensitive receptors and at the proposed plant's property line. Applicable noise criteria were provided to determine the significance of the projected noise levels.

Harbor Generating Station EIR – Port of Los Angeles, CA — Prior to joining Kimley-Horn Mr. Fuller prepared a noise technical report for the Los Angeles Department of Water and Power (LADWP) evaluating the potential noise impacts of demolishing two existing steam generators and constructing a replacement gas turbine generator at the Harbor Generating Station. Ambient noise levels from the power facility were characterized using a number of in-field measurements onsite, at the project site boundary, and at adjacent sensitive uses in the project vicinity. The proposed construction traffic routes were also evaluated for the impact of increased truck traffic on noise sensitive receptors. Estimates of construction noise levels were formulated based on equipment usage information provided by LADWP.

Delano Biomass-fired Power Plant Noise Technical Report, Thermo Electron Energy Systems, Bakersfield, CA — Prior to joining Kimley-Horn Mr. Fuller prepared an acoustical analysis to evaluate potential noise impacts associated with expansion of the existing 27-MW (net) output biomass-fired power plant (phase I) to include an additional 21-MW (net) power plant. Onsite noise monitoring of the cooling tower, front-end loaders, chippers, hog, stacker/reclaimer, boiler, turbine, and trucks was used to determine future site operation noise levels. Noise attenuation calculations were used to estimate future noise levels at the closest sensitive receptors to the site. Future noise levels were found to be consistent with the Kern County Noise Element of the General Plan.

Carson Hydrogen Facility – Praxair, Inc., Carson, CA — Prior to joining Kimley-Horn Mr. Fuller prepared a noise section of an EIR that evaluated potential noise impacts associated with construction and operation of the gas hydrogen plant and 27-megawatt steam cogeneration facility. Acoustical calculations were performed to project noise levels to the facility property line and to the closest noise-sensitive receptors. A detailed impact assessment was also prepared along the underground pipeline alignment.

Glendale Grayson Unit 9, Glendale Water and Power, Glendale, CA — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis for the addition of an LM6000 peaker unit and ancillary components at the existing power plant in the City of Glendale. The analysis consisted of detailed noise modeling and extensive field analysis. The plant subsequently has been approved to operate.

Louisa County Virginia Power Plant, Entergy Energy, Louisa County, VA — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis for the Louisa County Power Plant Project. The Proposed Action is to construct, operate, and maintain a nominal 1000-megawatt (MW) natural gas-fired, combined-cycle power plant and ancillary facilities. The analysis was based on detailed sound level measurements and acoustical modeling.

Puerto Viejo Power Plant, Dominican Republic — Prior to joining Kimley-Horn Mr. Fuller served as Noise Task Manager for a proposed 250-MW coal fired power plant in the Dominican Republic. Evaluated noise impacts based on The Republica Dominica Secretaria de Estado de Medio Ambiente y Recursos Naturales criteria and World Bank noise standards.

UCSD Central Utilities Plant, University of California, San Diego, CA — Prior to joining Kimley-Horn, Mr. Fuller prepared a noise technical report that assessed potential noise impacts from the addition to the Central Utilities Plant. Project components included boilers, chillers, miscellaneous pumps, and the expansion of the cooling tower. Mitigation measures were recommended to minimize noise at nearby sensitive land uses.

ExxonMobil Offshore LNG Re-gasification Project, ExxonMobil, Gulf of Mexico — Prior to joining Kimley-Horn Mr. Fuller prepared a noise section of the environmental documents submitted to the U.S. Coast Guard in support of a Deepwater Port Application for the proposed Pearl Crossing LNG receiving and re-gasification terminal about 40 miles offshore in the Gulf of Mexico. In addition to the terminal, the project consisted of connecting natural gas pipelines to a landfall near Johnson's Bayou, Louisiana and a 64-mile overland pipeline to a tie-in with existing pipeline facilities. The project also included development of a new graving dock at a coastal location for construction of the offshore terminal, which will be floated and towed to its final operational position. Because the project included components in different federal jurisdictions, the impacts associated with the pipeline and metering stations were addressed in a separate application to the Federal Energy Regulatory Commission.

Sayre NSS (Station 184) Equipment Noise Specifications Review, Kinder Morgan, Various, OK — Mr. Fuller reviewed bid documents for the equipment proposed for the expansion of the Kinder Morgan gas compressor station in Oklahoma. The review focused on specifications provided by Caterpillar for the proposed equipment (G3612 and G3616) to ensure compliance with FERC requirements.

Interstate Gas Transmission Project, CO. Kinder Morgan, Weld County, CO/Cheyenne, NE — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis in accordance with the FERC noise assessment criteria to construct and operate both new and expanded compression facilities on a segment of its interstate natural gas pipeline which extends from the Cheyenne Hub (Rockport Station) in Weld County, Colorado northeastward approximately 100 miles to the Huntsman Storage Facility in Cheyenne County, Nebraska.

TransColorado Expansion Project, Kinder Morgan, Various Locations, CO — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis in accordance with the FERC noise assessment criteria to construct or modify five compressor stations at various locations in Colorado. Major noise sources associated with the project included the generators and compressor engines and cooler fans. Noise from construction was also assessed.

Los Angeles County Metropolitan Transportation Authority, Initial Study/Negative Declaration for Division 3 Compressed Natural Gas Project, Los Angeles, CA — Prior to joining Kimley-Horn Mr. Fuller prepared an analysis that assessed potential noise and vibration impacts associated with the construction and operation of a natural gas facility for the Los Angeles bus fleet. The existing noise environment was described. Sound levels from the compressors and other components were projected to the residential receptors in the project vicinity. The potential for impacts from ground borne vibration was also assessed.

Oklahoma Resource Management Plan/EA, U.S. Bureau of Land Management, OK — Prior to joining Kimley-Horn Mr. Fuller prepared a noise analysis for an EA to amend a 1994 Resource Management Plan (RMP) to address the potential incorporation into the RMP of three geographic areas in Haskell, Latimer, and LeFlore Counties in southeast Oklahoma. The proposed activity would consist of coal recovery by surface mining and underground mining methods.

Northstar Unit Environmental Impact Statement, British Petroleum Exploration Inc., AK — Prior to joining Kimley-Horn Mr. Fuller prepared a noise section to an EIS prepared for the U.S. Army Corps of Engineers District, Alaska with the cooperation of the Minerals Management Service, U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, and National Marine Fisheries Service. The project consists of the development and production of oil and gas from the Northstar Unit located approximately six miles offshore of the Point Storkersen area in the Alaskan Beaufort Sea. Noise impacts to humans and wildlife from activities from project construction, operation, maintenance, and abandonment were evaluated. Construction impacts include those associated with ice road construction, reconstruction of Seal Island, including gravel haul and placement; installation of subsea pipelines and onshore oil and gas pipelines; installation of island facilities; and noise from construction activities, phase drilling, vessel traffic, and helicopter flights.

TESTIMONY

Prepared Direct Testimony
Of
Gary Chandler

1. Q. What is your name and place of employment?
   A. My name is Gary Chandler and I am president of Panoche Energy Center, LLC (PEC). My résumé is attached.

2. Q. What is the purpose of your testimony in this proceeding?
   A. I am responsible for permitting, constructing, and financing the project as well as keeping the project viable. My testimony principally focuses on the overall constructability and financing of the PEC project.

3. Q. Does PEC concur with the cost and impact evaluation done by Staff regarding its preferred alternative of using water from the semi-confined aquifer?
   A. Absolutely not. We appreciate that Staff made an effort to find a way to treat water from the semi-confined aquifer but, unfortunately, Staff's costs and impacts are without any engineering foundation, are not based on a thorough analysis of the water quality, and are completely erroneous as will be demonstrated by our witnesses. We have spent thousands of dollars both with URS and Bibb and Associates asking them to evaluate every possible way to use the semi-confined aquifer. Every feasible treatment method was evaluated over several months time. I am here to testify that Staff's water plan and suggested unproven and untested technology for application to the treatment of the semi-confined aquifer water and very incomplete cost analysis is not financeable or sound and would result in the cancellation of the project.

4. Q. Why would the project not be financeable?
   A. In most cases (including here), independently-owned power plants are financed through a project financing which means that the lender's recourse for recovery of its loan is only through the assets of the project. Typically, the project will be financed with about 80% debt and 20% equity. I have participated in or directed the financing of at least 30 power projects and can tell you that the lenders are very conservative and will never provide financing for questionable or unproven technologies or proposals lacking sound engineering and proven application or financial models based on speculative costs. The lenders will hire their own independent engineer to review and approve all critical areas of plant design prior to obtaining their internal approvals and financial closing. If Siemens Water Technologies is willing to step up and provide a parent guarantee that their system will work at the proposed capital and operating costs, it might be financeable, but only if it can be demonstrated that it will actually work in this application.

5. Q. What is the overall status of the Panoche Energy Center?

A. Panoche Energy Center executed a fixed price power purchase and sale agreement with PG&E in March 2006 for delivery of peak and intermediate load power by August 1, 2009. Since the contract pricing is fixed, Panoche has no ability to raise the price to PG&E for changes in costs and we have already seen the costs go up substantially on this project. Panoche executed an agreement for purchase of the turbine generators with GE in September 2006 and an EPC fixed price contract with Kiewit Industrial Company in July 2007. Panoche gave KIC a limited notice to proceed in July of this year for engineering and ordering of long lead items such as transformers, compressors, and steel. Panoche is required to give KIC a full notice to proceed by February 1, 2008 or the fixed pricing and guaranteed completion date of August 1, 2009 will go away.

6. Q. What is the nature of the construction contract with Kiewit Industrial Company?

A It is a turn-key contract whereby Kiewit is required to deliver an operating plant to us that will meet the requirements of the power purchase and sale agreement. Kiewit guarantees that the power plant and all associated systems will function as designed and engineered for a plant that will have frequent starts and stops. Kiewit is required to use suitable materials and equipment in designing and constructing the plant. The water treatment system is a very critical element of the design and construction. Kiewit is relying on Bibb and Associates, a sister company, to provide all design and engineering for the project.

7. Q. Is Kiewit willing to install and guarantee the filtration system proposed by Staff?

A. Kiewit is not willing to install or guarantee such a system as there are no such systems in use for this type of application. Bibb and Associates has already designed a proven system for use with the confined aquifer. If we are required to use the semi-confined aquifer and use an untested technology, Kiewit would no longer guarantee the performance or operation of the facility. That would also result in cancellation of the project as no lenders would be willing to finance such a venture.

8. Q. What is the owner of Panoche Energy Center's commitment to this project?

A. The owner of Panoche Energy Center is US Power Fund II which is owned by Energy Investors Funds. The largest investor in US Power Fund II is the California Public Employees Retirement System. At this moment Energy Investors Funds has invested approximately $18 million in the project and has additional liabilities of $18 million for a total commitment of $36 million. By the end of December 2007, this amount will increase to $52 million due to additional payments to the EPC contractor and GE. Almost that entire amount will be forfeited if the project is cancelled. The FSA misrepresents the ongoing costs that PEC is incurring on page 4.9-45. The ongoing approximately $4 million per month cost is not an incremental cost to the project but rather part of the budgeted cost for engineering, equipment acquisition, and permitting. It is not, as the Staff states, "one month of ongoing licensing process expenses,..." The ongoing licensing expense is only a small fraction of the monthly cost. I indicated the $4 million monthly cost to Staff to inform them of our commitment and level of funding to keep the project moving forward and assure an on-time completion.

9. Q. Previously you stated that PEC reviewed every water alternative and the feasibility of those sources including the semi-confined aquifer. Was that information provided to staff?

A. Yes. On March 2, 2007 PEC filed a technical memorandum entitled: "Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives". This document addressed a number of alternatives to the proposed confined aquifer water source. PEC filed a second technical memorandum on March 23, 2007, a third technical memorandum addressing water quality on April 24, 2007, and finally a letter from me to Dr. James Reede on July 27, 2007 that summarized our data and gave our conclusions. The central points of these memoranda were the cost and schedule impacts to make the semi-confined aquifer water and other alternatives acceptable for power plant use. If any other alternative was suitable at a reasonable cost and schedule impact, we would certainly agree to such an alternative.

10. Q. Is Staff's proposed water source alternative economically unsound?

A. Based on the real costs and schedule impacts of treating the semi-confined aquifer water, the alternative is economically unsound. The Commission has previously defined economically unsound as "economically or otherwise infeasible." Feasible means "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors." (Tesla Power Project, 01-AFC-21, Final Decision, June 16, 2004 at pages 316-317) At the true costs for treating the semi-confined aquifer water, the project is no longer economically viable nor can it meet its required delivery dates under the agreement with PG&E.

First, the capital and operating costs of the proposed alternative are prohibitive (see testimony of Steve Garrett). If the PEC were forced to pay an additional $19.5 million capital and $2.1 million annual O&M cost for the semi-confined aquifer water, these costs would have to be borne by the project owner as the PG&E contract has fixed prices.

Second, the Staff analysis is completely inaccurate. Treatment of the semi-confined aquifer water would require additional land and there is insufficient time to acquire additional land, rights-of-way, Williamson Act cancellation, air modeling, and obtain other regulatory approvals required if the Staff alternative is adopted (See testimony of Maggie Fitzgerald) and still meet the Notice to Proceed deadline of January 31, 2008 in the EPC Contract. After February 15, 2008, the fixed price in the EPC contract goes away and the guaranteed completion date is subject to renegotiation. It would take many months to accomplish all of the regulatory activities associated with expanding the site and changing the project layout. Missing these dates means a much higher construction price and missing the PG&E contractual on-line date of August 1, 2009. The impact on the schedule would most certainly result in cancellation of the project.

11. Q. Could the Panoche project use dry cooling?

A. No. Because of the extremely hot conditions in this area and the significant reduction in efficiency at high temperatures, Panoche would be required to add a fifth unit to meet its contractual obligations to GE. Besides adding at least $70 million in cost to the project, there would be significant other environmental impacts due to additional land requirements, additional pollution, additional water usage, and additional fuel usage.

12. Q. Are there other implications if this project is cancelled?

A. Yes. There will be social consequences of PG&E not having planned energy and capacity. Because of substantial price increases in engineered equipment, turbine-generators, steel, copper, and labor, the prices bid by developers in the next round of RFO's will be significantly higher than the Panoche project. Additionally, there will be a significant loss to Fresno County in property taxes and good paying jobs will be forfeited. Furthermore, Kiewit has contracted with the California Building Trades for construction of this project. Cancellation will result in a loss of work for over 300 workers.

13. Q. Staff, at FSA page 4.9-28, gives its reasons for not supporting the enhancement program with Westlands Water District previously proposed by PEC. Have you proposed a revised enhancement program to Westlands since the FSA?

A. Yes. Despite our disagreement with Staff regarding state water policy and with the on-going encouragement of Staff, PEC has reached agreement with Westlands Water District to contribute to one of their conservation programs—the Irrigation Systems Improvement Program. This program provides farmers with financing for new sprinklers, micro-irrigation, linear-pipe or central-pivot irrigation systems and tailwater reuse systems. Generally these water-saving irrigation techniques are replacing surface water supply irrigation. Westlands has agreed to the language in the Memorandum of Understanding that we have negotiated with them and which we have previously provided to Staff. Westlands is not willing to execute the MOU until the project is licensed by the CEC.

14. Q. What is the quality of the water saved with this program?

A. The water saved generally comes from the California Aqueduct, which is significantly higher quality than the confined aquifer water. In other words we would be more than offsetting our water usage by saving high quality water that is actually used for irrigation.

15. Q. Have you calculated the water savings over the life of the Panoche Project?

A. Initially Panoche proposed to Staff and Westlands to make a contribution in the amount of $500,000 based on saving much higher quality water. However, Staff objected to the use of differing water quality to calculate the offset. We have now determined that we will make a one-time contribution shortly after financial closing and approximately 18 months prior to commercial operation in the amount of $1.5 million to Westlands Water District. Westlands calculated an annual water savings of 628 acre-feet based on this amount. Since the loans to farmers are repaid every four years, the amount of savings becomes 1254 acre feet starting in year five and continues into perpetuity. Westlands estimates that all improvement projects will conservatively have a life of at least eight years. If Panoche uses its maximum projected water amounts (which is highly unlikely) over the life of the project, the amount of much higher quality surface water saved will be about 8% more than the much lower quality water used by Panoche.

16. Q. In its Final Staff Analysis, Staff, in Condition of Certification SOIL & WATER-8 stated: "The project owner shall use groundwater from the semi-confined aquifer supplied from on-site project wells as its water supply for landscape irrigation and all process uses including fire protection, plant service water, cooling tower makeup, combustion turbine NO_x injection and combustion turbine inlet air evaporative cooler makeup." Do you have any initial comments on this condition?

A. Yes. It is totally unacceptable. As I stated above, if the Commission adopts this Condition, there will be no project.

17. Q. Do you have a proposed condition that Panoche is willing to accept?

A. Yes. I would replace Staff's proposed Soil & Water 8 with the following condition:

The Project Owner shall make a one-time contribution of $1.5 million to Westlands Water District to be used in Westlands Water District's Irrigation Systems Improvement System program.

Add to VERIFICATION

Within 60 days following commencement of construction, the Project Owner shall provide the CPM proof that the payment has been made.

18. Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I prepared and am sponsoring Exhibit 30, my letter to Dr. James W. Reede, Jr. dated July 27, 2007 . The technical, engineering, and economic data contained in that letter were provided by members of the project team. Many of the points that I am testifying to here today are contained in that letter.

19. Q. Does that complete your testimony?

A. Yes, it does.

41

Prepared Direct Testimony
Of
Maggie Fitzgerald

1. Q. Please state your name and place of employment
   A. My name is Maggie Fitzgerald and I am a chemical engineer and Senior Project Manager for URS Corporation. My résumé is attached.

2. Q. What are your responsibilities with regard to the Panoche Energy Center?
   A. I am the URS Project Manager.

3. Q. What is the purpose of this testimony?
   A. Staff is recommending that PEC use the upper or semi-confined aquifer to provide the PEC water supply. I am here to describe how this alternative source of water would result in additional and unnecessary negative environmental impacts and significant project delays.

4. Q. Please discuss the semi-confined aquifer option.
   A. I believe that the use of this water source, as opposed to the PEC preferred confined aquifer, would result in environmental impacts that are possibly significant and certainly unnecessary.

5. Q. Please describe the environmental impacts associated with the use of the semi-confined aquifer option.
   A. The project engineers have determined that an additional 2 acres of land would be required to accommodate the extra water treatment equipment. There are many environmental impacts associated with the acquisition of 2 additional acres of land, including:
   - The USFWS Biological Assessment, Biological Opinion, and Memorandum of Understanding between PEC and FWS would need to be revised to account for the removal of additional kit fox foraging and habitat area. Depending on how USFWS would classify this change in acreage, additional biological surveys may be required.
   - Second, the 2 acres is zoned agricultural and would result in the removal of an additional 2 acres of prime farmland and be subject to the Williamson Act cancellation process.
   - Third, use of the semi-confined aquifer water would require the installation of a lime and soda ash softening system and a larger reverse osmosis system. Up to 3,500 tons of solid waste would be generated by these systems and require disposal to an off-site landfill. This would result in additional traffic impacts and unnecessary use of landfill capacity. Further, the larger RO system would increase the overall raw water consumption by about 11%

or about 109 acre-ft per year, increasing the impact to water resources.

- Finally, the changes to the water treatment systems would result in a 44% increase in the amount of wastewater discharge

6. Q. What are the schedule implications of the PEC having to acquire an additional 2 acres of land and obtain all necessary regulatory approvals?

A. Assuming that the property owner will lease the land at a reasonable price and that a lease could be accomplished in a timely manner, there are two project timing issues:

- First, PEC submitted a Biological Assessment to USFWS on May 18, 2007. The Service based their Biological Opinion on this document as well as other pertinent data. The Biological Opinion was issued on August 21, 2007. If the Commission determined that water from the semi-confined aquifer was required, and assuming an additional 2 acres of land would be necessary, the Biological Opinion and MOU would require revisions. USFWS estimates that an amendment to the Biological Opinion and MOU would require up to 2 months and this assumes this change can be classified as minor.
- Secondly, Fresno County completed its procedure for canceling the Williamson Act designation of the 12.8 parcel on May 9, 2007, approximately 6 months after the landowner filed for cancellation. If the Commission were to order the use of the semi-confined aquifer, thus requiring taking additional lands out of Williamson Act protection, an additional approximately 6 months would be required.

8. Q. What are your conclusions with regard to the use of the semi-confined aquifer?

A. It is my opinion that the use of semi-confined aquifer water would have additional and unnecessary environmental impacts. Of much greater concern is the additional time required to evaluate and permit additional land required for additional treatment facilities. If, for example, the Commission were to order use of semi-confined aquifer, the acquisition of additional land and obtaining all necessary approvals would take a minimum of 5-6 months, making these options impracticable.

9. Q. Are you sponsoring any exhibits?

A. Yes.
Exhibit 9, PEC Comments to PSA, July 26, 2007
Exhibit 11, USFWS Biological Opinion, dated August 21, 2007
Exhibit 27, Technical Memorandum: Expanded Evaluation of Water Supply and Wastewater Discharge Alternatives, March 2, 2007 (portions)
Exhibit 28, Technical Memorandum: Supplemental Discussion of Water Supply and Wastewater Discharge Alternatives, March 23, 2007 (portions)

Exhibit 29, Technical Memorandum: Water Quality Evaluation, April 24, 2007 (portions)

10. Q. Does that complete your direct testimony?
A. Yes, it does.

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Prepared Direct Testimony
Of
Charles Fritz.

1. Q. Please state your name and place of employment.

A. My name is Charles Fritz and I am a registered Professional Engineer and a Senior Water Chemistry Consultant with Bibb and Associates, Inc., a consulting engineering firm with its principal office in Lenexa, Kansas.

2. Q, What are your duties and responsibilities with regard to the PEC project?

A. Our firm has been retained by PEC, LLC as the project engineer. I am the Project's water treatment consultant for Bibb and Associates.

3. Q. The Staff (FSA, page 4.9-37 to 45) is advocating the use of a multimedia and nanofiltration softening system as an appropriate alternative to the lime and soda ash softening system you prefer. Have you evaluated this Siemens system?

A. Unfortunately, the Staff is making a recommendation for a hastily conceived water treatment system with missing design elements that exposes the owner to serious operational risks. The Staff's promotion of the nanofiltration technology is based on abbreviated reviews by Siemens and Aquatech without considering all the implications of the constituents in the poor quality semi-confined aquifer.

Water treatment companies typically design nanofiltration and reverse osmosis systems using Dow's Reverse Osmosis System Analysis Program (ROSA), or a similar simulation program. The ROSA program allows the user to configure a treatment system within the membrane manufacturers design limitations and includes chemistry limitations to warn of scaling and fouling potential. Siemens indicated in a telephone communication that a design simulation was not done. Aquatech indicated that they did run ROSA, but only with partial water constituents as provided by the CEC staff. Attempts were made to simulate the Siemens NF design, although the information provided by Siemens was insufficient for an accurate simulation. Filmtec NF90-400 elements were selected to obtain similar permeate quality and Silt Density Index and temperature were input as SDI < 3 and 12.8 C (55 F), respectively.

When all water constituents are entered into ROSA, the program would not allow a design with 80% recovery as proposed by Siemens and provides two design warnings, indicating that the design must be altered to comply with the membrane manufacturer's recommendations. The design warnings indicated that the system design should be changed to reduce the element permeate flows and to reduce element recoveries. These warnings indicate that the system offered is under-designed with respect to membrane area and that the recovery is overstated.

4. Q. Were there other warnings from the ROSA program?

A. Yes. The ROSA program also provided five solubility warnings that indicate severe scaling potential plus indications that both the Langelier and Stiff & Davis indexes project unstable chemistry. The ROSA program also shows the percent saturation of scaling constituents including $BaSO_4$ at 4,579%, CaF_2 at 3,633%, $CaSO_4$ at 219%, and SiO_2 at 202%. This coincides with Bibb's experience and expectations for water containing such high levels of hardness, particularly calcium and magnesium, sulfate and silica. Antiscalants are needed to control scaling in the membranes. Antiscalants are available from several sources for this purpose, but their performance is not assured without testing. Common practice is to operate membrane systems at lower recovery rates than predicted by the design program to provide a margin of safety against scaling due to variations in water chemistry and/or poor antiscalant performance. Based on these preliminary design results, a prudent design would consist of a larger system with a lower recovery rate. Alternatively, pretreatment could be used to achieve the desired reliability by removal of scaling constituents from the feed water.

5. Q. What have you concluded about the use of an NF softening system for PEC?

A. Although nanofiltration (NF) softening is theoretically possible, there are several major omissions and concerns that result in unacceptable risk to the project, including the following:

(a) The semi-confined aquifer contains iron and manganese. These constituents cannot be tolerated by membrane systems and must be removed by pretreatment. The Siemens conceptual design ignores this requirement and does not address the significant additional treatment equipment and space associated with an effective pretreatment system.

(b) NF systems are designed for continuous operation. When not in operation, as would be a frequent occurrence with a project designed for peaking service, the membranes must be layed up with a chemical solution that will control biological activity. Failure to follow such industry accepted procedures can result in failure of the membranes. The Siemens proposal omits the facilities necessary to automatically layup the NF system and does not address the time required for layup, subsequent flushing before the system can be returned for service, or the added cost of the disinfectant solution and disposal of the additional wastewater produced. Our observation, which directly contradicts Staff's contention, is that the NF system is not capable of rapid start under these conditions.

(c) The conceptual design for the NF system as proposed by Siemens represents a significant risk when treating the highly mineralized water of the semi-confined aquifer. We have been unable to confirm the ability to inhibit scaling with commercial antiscalants when operating at the high (80%) recovery rate proposed. Further investigation with antiscalant suppliers using the output forms from a detailed software simulation based on the complete water analysis is necessary to resolve this issue. A further concern that cannot be readily resolved is the ability to control scaling in the injection wells and in the injection formation. The potential for chemical precipitation when the supersaturated reject solution is mixed with fluids in the injection formation is an unacceptable risk to the project.

(d) NF is not typically used for treatment of cooling tower makeup for a power plant. We are not aware of any such system that is currently being used in this application. Our experience indicates that NF systems are more complex than conventional treatment processes such as lime and soda ash softening and typically have greater potential for upsets resulting in lower reliability. We believe a greater degree of redundancy than proposed by Siemens is necessary to offset these impacts.

6. Q. Staff also believes this Siemens system (or alternate Aquatech system) would be significantly cheaper than the Applicant's preferred system. Have you had an opportunity to review Staff's cost figures?

A. Yes. I offer the following observations.

(a) Staff's cost figures for the Siemens conceptual design do not appear to be realistic based on our experience with the purchase and installation of similar power plant quality equipment.

(b) A pretreatment system required for removal of iron and manganese is not included.

(c) Recovery of 80% appears to be unachievable based on the preliminary simulation program runs that incorporate all constituents in the raw water. This results in an undersized system and understates the amount of additional water required and wastewater generated.

(d) Six 20% capacity treatment lines do not provide the desired level of redundancy.

(e) Facilities for frequent layup of the NF pressure vessels for protection from biological activity are not included.

(f) Feedwater chlorination is required for effective biocontrol, but is not included.

(g) No allowances are included for interconnecting piping and valves, field installed wiring and controls, or for additional power supplies.

(h) Costs associated with backwashing large filters and disposing of the wastewater are not adequately addressed.

7. Q. If properly designed, would the cost of the NF system be competitive?

A. We have not developed a preliminary design for a NF alternate, so an estimate of the installed cost must be considered a "ballpark" estimate. If the system were to be modified to include the omissions listed above, the estimated NF system equipment cost would be in the range of $7 to $9 million. This estimate is consistent with Aquatech's estimate of over $5 million for the base system without the required additions. Our experience indicates that the installed equipment cost would be at least double the equipment cost not including additional tankage for pretreated water or additional wastewater handling, treatment, and disposal costs. On this basis, the NF system cost would be at least as much as the lime and soda ash softening plan. Regardless of the cost of a properly designed NF system, we would not recommend this alternative because of the unacceptable risk related to system reliability and injection well operation.

8. Q. Does that complete your direct testimony?

A. Yes, it does.

Prepared Direct Testimony
of
Stephen Garrett

1. Q. Please state your name and place of employment.

A. My name is Steve Garrett and I am a registered Professional Engineer and a Senior Project Manager with Bibb and Associates, Inc., a consulting and engineering firm with its principal office in Lenexa, Kansas. My résumé is attached.

2. Q. What are your duties and responsibilities with regard to the PEC project?

A. Our firm has been retained by PEC, LLC as the project engineer. I am the PEC project lead with Bibb and Associates.

3. Q. Please describe the design parameters imposed by the PEC – PG&E power purchase agreement.

A. There are three significant design parameters that we considered: (1) the units are to be capable of ramping from a cold condition to 100% load in 10 minutes, (2) each unit must be capable of delivering 95.2 MW of capacity (net) in peak summer conditions, and (3) each unit must be fully dispatchable as system conditions require.

4. Q. How does the General Electric LMS100 use water?

A. The LMS100 is the first inter-cooled combustion turbine system developed specifically for fast start peaking power generation. The LMS100 utilizes an intercooler for the inlet air as it is compressed, allowing for approximately 10 percent greater thermal efficiency than other commercial simple cycle units. Exhibit 34 illustrates the intercooler design.

Cooled water from a conventional mechanical draft cooling tower is directed through the tube side of a shell and tube heat exchanger. The combustion air flows on the shell side of the heat exchanger and is cooled before it reenters the high-pressure compressor section of the combustion turbine.

Water is also treated and injected into the combustion turbine for NOx emission control and for cooling the ambient air at the inlet of the combustion turbine to improve efficiency.

5. Q. PEC has proposed to use the water in the confined, or lower, aquifer for its water supply. Have you evaluated the treatment necessary for the use of this water?

A. Yes. This water is suitable for use in the General Electric LMS100 combustion turbines, the cooling tower, and other plant auxiliary equipment after treatment. Exhibit 33 is a water mass balance for the plant that shows the key water treatment equipment required plus it shows the flow paths of the various water streams considering combustion turbine manufacturer quality requirements and increased cooling tower cycles of concentration.

6. Q. The CEC Staff is advocating the use of the semi-confined aquifer for the PEC's water requirements. Have you evaluated the differences in water quality between the two sources that are of importance to plant design?

A. Yes. Mr. Jason Moore has provided the water analysis for this water. The semi-confined water has the following key characteristics:

- The semi-confined aquifer water has a hardness of about 1100 milligrams per liter (mg/L), which is 20 times greater than water from the confined aquifer.
- The semi-confined aquifer water has a TDS of about 2900 mg/L, which is 3 times greater than water from the confined aquifer.
- Calcium and magnesium concentrations in the semi-confined aquifer water are about 10 and 45 times greater, respectively, than concentrations found in the confined aquifer water.
- Sulfate concentrations exceed approximately 1,500 mg/L, which is about four times the concentration found in the confined aquifer water.
- Chloride concentrations are about twice those in the confined aquifer.
- Silica concentrations are about 1.5 to 2 times those found in the confined aquifer.

7. Q. What are the water treatment implications of the use of the semi-confined aquifer water?

A. The water quality parameters of the semi-confined aquifer are of particular concern for operation of the PEC. A significant lime and soda ash softening pre-treatment system (solid contact unit or SCU) would be required to reduce calcium and magnesium hardness and silica to levels that would not result in scaling of the power plant equipment. Additionally, the sulfate and chloride levels would need to be reduced for use in the cooling tower with a reverse osmosis system (RO). All of the well water from the semi-confined aquifer would have to be processed through the lime and soda ash SCU. Solid waste precipitated from the SCU would be processed in a thickener and filter presses prior to being trucked offsite and landfilled. Up to 3,500 tons of solid waste would be generated each year. This material would have to be trucked off site to a landfill.

A large portion of the softened water (about 40%) would be directed through the RO system to reduce sulfates and chlorides and then used in the cooling tower. This would increase the size of the RO that is required for the confined aquifer water by a factor of 2.5. The RO rejects would increase the overall raw water consumption by about 11% (109 acre-ft per year).

8. Q. What are the cost and land requirement implications of this required treatment?

A. The lime and soda ash softening pretreatment system to reduce hardness and silica plus the reverse osmosis (RO) system to reduce sulfates and chlorides is estimated to cost approximately $18 million. Exhibit 35 presents the capital cost estimate. This cost includes the SCU, RO, filters, silos for lime and soda ash storage, thickener, filter presses, controls, wiring, foundations, piping, and a 2-million gallon storage tank to offset the ramp-up time of the softener equipment. Staff's value of $12 million (FSA, page 4.9-35) does not include the cost contribution of an expanded RO system to reduce chlorides and sulfates in the water for the cooling tower. The changes to the water treatment systems would result in a 44% increase in wastewater injection requirements, which, in turn, would require at least one additional injection well at a cost of approximately $1.5 million for construction. The total impact to the project is $19.5 million in extra capital expenditures.

Annual operations and maintenance costs (O&M) attributable to the water treatment equipment for the semi-confined aquifer water is estimated to be $2.14 million per year as indicated in Exhibit 30. These costs would be in addition to the annual O&M costs for the plant when using water from the confined aquifer. The added O&M costs include expenses associated with power consumption for electrical equipment, additional permanent plant staff to operate the equipment, costs for repair parts and specialty maintenance repair contractors, expenses for purchasing lime and soda ash, and costs for hauling away the solid waste to a landfill.

The extra water treatment equipment would not fit on the current PEC parcel and additional land would be required. The additional land required to accommodate the extra water treatment equipment is estimated to be about 2 acres.

9. Q. The Staff (FSA, page 4.9-37 to 45) is advocating the use of a multimedia and nanofiltration softening system as an appropriate alternative to the lime and soda ash softening system you prefer. Have you evaluated this Siemens system?

A. Yes, I have evaluated the proposed system. There are numerous design and operational deficiencies in what has been offered as a feasible treatment system (see Prepared Testimony of Charles Fritz and Joseph Gruemmer). Additionally, the capital costs as presented by Staff do not represent fixed price EPC contracting, where guarantees for schedule, price, and performance are required. Staff contacted two suppliers of nanofiltration (NF) equipment to get their quotes for supply of the equipment. Quotes and statements of feasibility using the semi-confined aquifer were obtained from each. Staff used the lowest quote to prepare the FSA (FSA Table 17, Page 4.9-1). The alternate quote for equipment supply was another $2 million higher, clearly indicating uncertainty in design philosophy, scope, and quality of materials. Detailed material specifications have not been provided to the Staff so the quality of the equipment to satisfy the stringent equipment requirement of the PG&E power purchase is indeterminate. The Staff added 10 percent contingency, which at time of conceptual design is insufficient. Staff estimated engineering and construction costs to be 50 percent of the equipment supply. Again, this amount is insufficient. My experience indicates, absent a detailed and time-consuming material takeoff, that the construction cost is at least as great as the equipment supply to account for foundations, piping, electrical installation, controls, and buildings. Missing from the Staff cost estimate and typical of EPC contracting are amounts for contingency, overhead, and profit. It is clear that the Staff wanted to show minimal incremental costs to the project for the semi-confined aquifer. Unfortunately this is not the case.

10. Q. Please discuss the time constraints on this project.

A. The use of water from the semi-confined aquifer would require additional time for land acquisition and permitting. The project has a fixed price Engineer, Procure and Construct (EPC) contract that requires 18 months from Notice to Proceed to the required on-line date. For every day of delay in the Notice to Proceed after February 1, 2008, there is a significant escalation payment and day for day extension of the scheduled completion date. After February 17, 2008, the EPC contract fixed price is subject to renegotiation. Given manpower and commodity price escalation that I am witnessing in the industry, I do not believe that the existing contract price can be held after the February 17, 2008 date.

11. Q. Staff has indicated that both the Wellhead Power Peaking Plant and the CalPeak Power Peaking Plant use water from the semi-confined aquifer. Also, the Starwood, currently seeking approval from the Commission, proposes to use water from the semi-confined aquifer. Why can these facilities use this water and PEC cannot?

A. The PEC could potentially use semi-confined aquifer water, but at a significant cost and with adverse schedule and environmental implications. The Wellhead and CalPeak units have much less generating capacity than PEC and they do not use water injection for NOx emission control. Additionally, the Wellhead and CalPeak plants do not use the latest in efficient combustion turbine designs with water-cooled intercooler technology. Therefore, they are less efficient with greater air emission characteristics. The proposed Starwood Midway project will require high quality water for NOx emission control and combustion air cooling, but does not use the efficient intercooler technology.

I understand that the CalPeak project was designed to use water from the semi-confined aquifer, but found treatment costs were prohibitive. They found that the demin trailers had to be changed out so often that it became cost prohibitive. This is consistent with my evaluation of the semi-confirmed aquifer as a water source.

12. Q. Please describe the constraints and impacts to equipment and project design that would be imposed by Conditions of Certification GEN-1 as contained in the FSA.

A. GEN-1 requires the design to be in accordance with the 2001 California Building Standards Code (CBSC) but qualifies this condition if there is a successor code in effect at the time the engineering designs are submitted to the CBO. In the Applicant's comments to the PSA dated July 26, 2007, the owner indicated that in order to have the plant on-line by August 1, 2009 major equipment had to be ordered in 2006 and 2007 based on the 2001 CBSC. Also, in order to support construction consistent with the planned on-line date, detailed design has been released based on the 2001 CBSC. The GEN-1 condition imposes a potentially significant expense to the owner to rework design calculations and documentation for submittal to the CBO. The Staff may not be aware of the code change or fully understand and appreciate the issues involved and expense to change applicable codes in the middle of a large project. The code successor provisions should be struck from GEN-1.

13. Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring parts of exhibits 27 through 30 and exhibits 33, 34, and 35.

Prepared Direct Testimony
of
Joseph Gruemmer

1. Q. Please state your name and place of employment.

A. My name is Joseph Gruemmer and I am a Senior Water Chemistry Engineer with General Electric Water and Process Technologies, a water treatment system supplier with its principal office in Minnetonka, Minnesota. My résumé is attached.

2. Q. What are your duties and responsibilities with regard to the PEC project?

A. As a Water Chemistry Engineer for GE and the power industry, I was asked by PEC, LLC to assess the Staff's proposal to use a multimedia and nanofiltration system for use with the high TDS semi-confined aquifer.

3. Q. What technologies do you provide to customers in your role at GE Water & Process Technologies?

A. GE offers every conceivable technology for water treatment to the power industry including reverse osmosis, nanofiltration, lime softening, and numerous other technologies. This has been made possible by GE's investment in leaders in the industry including Osmonics, Glegg, Ionics, Zenon, Ecolochem and other major suppliers of basic water treatment suppliers. My personal role is to evaluate the proposed semi-confined aquifer water source for the PEC project and to recommend systems and operating parameters that will be the most cost effective and operable for the customer.

4. Q. Have you evaluated this Siemens system?

A. I've run design simulations of nanofiltration technology using Osmonic's, Hydranautics and Dow membrane assessment programs. These programs are similar to each other with respect to how project performance is determined. All of the above programs give warnings with respect to a number of concentrated salts from the proposed raw water source. Although each program predicts somewhat different results for salt rejection, they all confirm that substantial pre-treatment of the membrane system is required to ensure reliable long term operation. There are numerous warnings listed, which is consistent with my experience using the highly mineralized water from the semi-confined aquifer. There are significant problems with nanofiltration considering the ultra-high sulfates that even acid feed will not address and only low recovery can mitigate. Also the phosphate, boron and any residual iron and manganese will play havoc with the nanofiltration membranes over time, increasing operation and maintenance costs. The iron and manganese constituents must be removed ahead of the membranes and such removal was not included in the Staff's assessment.

5. Q. Have you sold nanofiltration systems to any customer proposing to use water similar to the semi-confined aquifer water?

A. No. This would be an improper application without installing substantial pre-treatment mechanisms, like lime softening.

6. Q. In your experience, are there system designs that could be implemented that would mitigate the fouling and scaling problems inherent with nanofiltration using the high TDS semi-confined aquifer?

A. The only proven approach is to soften the water ahead of the nanofiltration system using a lime and soda ash clarifier. This would increase the capital and annual operating and maintenance costs of the water treatment system well beyond that indicated in the Staff's analysis.

7. Q. Are you sponsoring any exhibits in this proceeding?

A. No.

Prepared Direct Testimony
of
Jason Moore

1. Q. Please state your name and place of employment.
A. My name is Jason Moore and I am employed by URS Corporation as a Senior Geologist. I am a Professional Geologist and Certified Engineering Geologist licensed by the State of California. I have extensive experience in the evaluation of the geology and groundwater of Central California, which includes the immediate area of the PEC.

2. Q. What are your responsibilities with regard to the Panoche Energy Center?
A. I am the geologist assigned to this case. In addition to assessing geological hazards and resources of the site, I am responsible for the evaluation of the proposed water supply for the facility. I have evaluated the proposed water supply for both quality and availability.

3. Q. Where does PEC propose to obtain water for the PEC?
A. Groundwater within the region is present within an upper, semi-confined aquifer and a lower, confined aquifer separated by the Corcoran Clay (E-Clay) aquitard (Exh. 27, page 7 and Exh. 36). The Corcoran Clay retards mixing of and communication between the semi-confined and confined aquifers. PEC proposes to use groundwater within the confined aquifer underlying the site.

4. Q. Would you please discuss the quality of this confined aquifer water?
A. Water quality within the confined aquifer underlying the site is low in part because of the influence of deleterious soluble minerals in Coast Range sediments present within the aquifer. The confined aquifer water quality data summarized in Staff's FSA, page 4.9-13 is consistent with the site-specific data provided by the PEC. In Exhibit 29, page 2, I constructed a table that shows which chemicals and other constituents exceed maximum contaminant levels (MCL) established by the California Department of Health Services and/or USEPA. The Staff does not appear to consider the parameters that degrade water quality within the confined aquifer such as manganese, iron, sulfate and total dissolved solids concentrations as well as pH and specific conductance that exceed secondary MCLs.

5. Q. Is there competition for the water in the confined aquifer?
A. No. Groundwater modeling indicates that a supply well pumping quantities of water sufficient for the maximum operation period of the PEC would not produce noticeable drawdown within the aquifer. Relatively high quality surface water deliveries by the Westlands Water District have largely replaced usage of groundwater for domestic, municipal, and agricultural water supplies. Staff correctly noted that groundwater is used as a supplemental and backup supply for agriculture when CVP water is unavailable. Agricultural use of the water is typically limited to rare situations because the water presents threats to crops and soils including salinity, sodium, and boron hazards. In my opinion, the PEC water

requirements would have negligible impact on water available for intermittent agricultural demand. The maximum annual water demand by the PEC of 1,154 acre feet would be about 0.5 percent of the typical annual Westlands Water District groundwater demand of about 200,000 acre feet.

6. Q. Staff appears to suggest that municipalities, such as Mendota, entities such as the federal prison near Mendota, and residences, such as a residence 800 feet from the site, could be negatively impacted by the PEC's use of water from the confined aquifer. Do you agree?

A. No Few municipalities in the area use groundwater for their water supply, and those that do (*i.e.*, Mendota, Firebaugh) use higher quality water from a different aquifer. The Cities of Mendota and Firebaugh use wells completed above the Corcoran Clay for municipal water supply. Exhibit 36 is a cross-section of the geology underlying the PEC. This cross-section illustrates that City of Mendota wells are completed in a different aquifer. The FSA, at page 4.9-11, seems to imply that a cluster of homes in the area of the PEC would use water from the confined aquifer but that is not the case. There is no known domestic use of water from the confined aquifer in the area of the PEC.

7. Q. Would you please discuss the availability of the confined aquifer water?

A. Well yields within the Westside Subbasin of the San Joaquin Valley Groundwater Basin average 1,100 gallons per minute and average from 600 to 1,800 feet in depth. Lithologic and geophysical logging of sedimentary deposits underlying the site, as well as limited aquifer testing (*i.e.*, slug tests), indicate that geologic and hydrogeological properties of the aquifer are consistent with the surrounding area and the aquifer should be capable of producing average well yields. Prior to the construction of major canals or aqueducts, irrigation water in the region was almost wholly supplied by thousands of large and deep wells, and extractions of water reached at least 10 million acre feet in 1966. Delivery of surface water greatly reduced groundwater pumping in the area, and rapid decline of artesian head was reversed starting in the late 1960's and early 1970's. A hydrograph for a well close to the PEC monitored by the California Department of Water Resources shows generally rising groundwater levels as well as intermittent decreases associated with groundwater pumping during droughts (Exhibit 37). I agree with Staff's determination that well interference impacts caused by project pumping would be less than significant (See FSA, page 4.9-22)

8. Q. How many wells are located near the PEC?

A. As many as 12 existing or abandoned water wells have been identified within a one-mile radius of the PEC. Most of these wells have been abandoned, have collapsed, or are monitoring wells not used for groundwater production. A few functional irrigation wells within the confined aquifer are still present within the surrounding area, but are rarely used. Reconnaissance of wells surrounding the site did not identify any functional, operating wells that could be used to supply groundwater samples from the confined aquifer near the site. Therefore, I conclude that PEC's pumping impacts on other potential users of water from the confined aquifer would be negligible.

9. Q. Staff suggests that the PEC use water from the semi-confined aquifer. Have you analyzed the water in this aquifer?

A. Yes. Site-specific groundwater quality data for several sampling events in a well completed within the semi-confined aquifer underlying the site is compared to state, federal, and agricultural water usage quality limits in tables 3.1 and 3.2 of Exhibit 27. The groundwater sampling data from both the semi-confined and confined aquifer water samples indicate that both groundwater sources are of low quality. Based upon TDS levels alone, water from both aquifers could be considered "brackish" or "semi-brackish".

While total dissolved solids concentrations are higher for the semi-confined aquifer water (about 2,900 milligrams per liter) than the confined aquifer water (range from about 835 to 1,050 milligrams per liter), neither the confined aquifer water supply proposed by the PEC nor the semi-confined aquifer water supply proposed by the CEC meet the definition of "brackish" in California State Water Resources Control Board Resolution Number 75-58 because the chloride concentrations in both the confined and semi-confined aquifers do not exceed 250 milligrams per liter. A more recent CEC report entitled *Use of Degraded Water Sources as Cooling Water in Power Plants* defines brackish water as containing total dissolved solids exceeding 1,500 milligrams per liter and recognizes other constituents (*e.g.*, general minerals, biological, organic compounds, metals, other compounds) that degrade water. Elevated total dissolved solids and concentrations of other constituents degrade water quality in both aquifers, and both aquifers should be considered degraded water sources. Salinity concentrations used to define brackish water range widely, but can be as low as 500 milligrams per liter.

10. Q. Staff argues that PEC should be able to use water from the semi-confined aquifer because other power plants, such as CalPeak and Wellhead, use this water. Do you agree?

A. No. Although Staff appears to make this argument in FSA pages 4.9-32 and 33, at page 4.9-11 they state that the "only potential users of groundwater from the semi-confined aquifer near the project site are the proposed Starwood Power Plant and occasionally the CalPeak peaker power plant". We agree that the Wellhead power plant does not use groundwater. We have also been informed that the CalPeak facility does not use groundwater due to the poor quality of the water. The CalPeak facility constructed a well so that they could use water from the semi-confined aquifer, but found that the cost of treatment was too high and the well is no longer used.

11. Q. Staff also suggests that the Starwood facility will utilize this water. Do you have any observations on this use?

A. Starwood's water requirements appear to be much lower than the requirements of the PEC, and this may be the reason. I would point out that Starwood has also advanced the water alternatives of using agricultural backwash water or water from the confined aquifer. As this proceeding trails the PEC proceeding, I am not sure that Starwood can or will use water from the semi-confined aquifer.

12. Q. What would the impact of using semi-confined rather than confined aquifer water be with respect to water supply?

A. The water would be of lower quality, require treatment prior to use of all of the water rather than a comparatively small amount, and reduce the cycles of concentration available to the PEC. Relatively high concentrations of sulfate, along with other minerals dissolved in the untreated semi-confined aquifer water would be expected to cause significant encrustation, corrosion, and abrasion of pumps and related equipment leading to above average repair and maintenance requirements and costs. The potential for downtime of the supply wells and possibly the PEC itself would increase. Groundwater modeling indicates that a supply well pumping quantities of water sufficient for the maximum operation period of the PEC would produce about 10 feet of drawdown at the neighboring CalPeak Panoche Plant supply well about 2,640 feet from the modeled well. Progressively smaller drawdown would extend greater distances from the PEC. Drawdown at the CalPeak Panoche Plant well would be greater if both PEC and Starwood used the semi-confined aquifer due to well interference impacts.

13. Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Exhibit 1 sections 5.3 and Appendices L & R;
Exhibit 2 Geo-6 and Water 28-33;
Exhibit 3 Geo 34, 35, 37 and 38 and Water 45 to 48 and 50 and Appendices A and B;
Exhibit 36, and
Exhibit 37.

14. Q. Does that complete your direct testimony?

A. Yes

Prepared Direct Testimony
of
Stephen H. Ottemoeller, PE

1. Q. Please state your name and give your place of business.

   A. My name is Stephen H. Ottemoeller and I am employed by URS Corporation as a Principal Engineer. My résumé is attached.

2. Q. What are your duties and responsibilities at URS?

   A. I am the Director of Central Valley Water Resources and I am in charge of the Water Resources Group in the Fresno Office. I am a registered Professional Civil Engineer in California (License No. C38579). My responsibilities include business development related to water resources in the San Joaquin Valley. I am also the project manager for several individual projects from Tulare to the Sacramento-San Joaquin River Delta.

3. Q. What is the purpose of your testimony in this proceeding?

   A. PEC has retained me in this proceeding to determine the proper test to be used by this Commission in determining the suitability of the confined aquifer water for cooling water for this facility.

4, Q. Are you familiar with the water resources in the vicinity of the PEC site?

   A. Yes. I was employed by Westlands Water District from 1982 to 1998. My initial responsibilities included working to solve the subsurface drainage problems in the District, particularly in a 42,000-acre area immediately to the east of the PEC site. Starting in 1984, my responsibilities included oversight of all water supplies and water delivery operations in the District, including groundwater pumping programs during the 1987-1994 drought. I am very familiar with the uses and availability of both surface water and groundwater in the Westlands Water District for agricultural and domestic purposes as well as surrounding areas.

5. Q. Have you reviewed the Panoche Energy Center Staff FSA?

   A. I have reviewed a portion of the Soil & Water Resources section of the FSA, specifically the Water Use section. I have also read and am familiar with certain guidance documents, such as State Water Resources Control Board Resolution 75-58 (SWRCB 75-58), the 2003 Integrated Energy Policy Report (2003 IEPR) (Exhibits 31 and 32), and various Commission decisions interpreting the Commission's policy on power plant water use

6. Q. What guidance have you been given by PEC?

   A. I was told the general dilemma faced by PEC – that they propose to use water from the confined aquifer and the Staff opposes the use of this water on policy grounds. I was then asked to prepare an analysis of the application and interpretation of state policy used by Staff in evaluating the suitability of using inland waters for power plant cooling, and to determine if the PEC's use of water from the confined aquifer violates state policy.

7. Q. What conclusions and observations do you have?

A. The PEC's use of water from the confined aquifer does not violate state policy. I believe that the policy of the state of California is contained in the Commission's 2003 IEPR, which consolidated and re-stated previous state policy contained in SWRCB 75-58. In addition, use of the confined aquifer is consistent with prior CEC decisions.

8. Q. Please describe the appropriate test for determining whether a water source is consistent with state policy.

A. The most appropriate determinant of state policy for the California Energy Commission is the 2003 IEPR, which draws heavily upon SWRCB 75-58. In fact, the Commission has stated that "We did not create new, substantive water policy in the 2003 IEPR." (Blythe II, Final Decision at page 248). The most thorough analysis examines the following, in order:

(a) Does the water supply violate the 2003 IEPR? The 2003 IEPR dictates that the Commission will approve "fresh water" for cooling only if alternate sources are environmentally undesirable or economically unsound. If the appropriateness of the water supply is unclear, the Commission should consider the underlying policy document – the SWRCB 75-58

(b) Principle 1 of the SWRCB 75-58, which sets five water sources in descending order of priority,

(c) Principle 2 of the policy that dictates that the use of fresh inland waters for power plant cooling will be approved only where the use of alternate sources of water would be environmentally undesirable or economically unsound, and

(d) Principle 3 of the policy which calls for consideration of the reasonableness of the preferred water source when compared with other present and future needs of the water source.

9. Q. Looking at the 2003 IEPR, Staff states in numerous places in the FSA that water from the confined aquifer does not pass the 2003 IEPR test as it is "fresh water", and fresh water should be approved "only where alternative water supply sources and alternative cooling technologies are shown to be "environmentally undesirable" or "economically unsound". Do you agree with Staff's conclusion?

A. No. The water in the confined aquifer is not "fresh" and thus is an acceptable source of water for power plant cooling. The 2003 IEPR uses the term "fresh water" and SWRCB 75-58 uses the term "fresh inland waters". I believe these two terms are interchangeable. I believe Staff agrees with this assessment as the Staff recognizes, at FSA page 4.9-27, that the IEPR does not define "what constitutes fresh water". Staff then looked to SWRCB 75-58 for help with the definition, which defines fresh waters as: "those inland waters which are suitable for use as a source of domestic, municipal or agricultural water supply…" (FSA, page 4.9-27) The definition contained in the FSA, however, is terribly misleading. Read the entire definition from SWRCB 75-58 Definitions, at page 2:

> "Fresh Inland Waters – those inland waters which are suitable for use as a source of domestic, municipal, or agricultural water supply **and which provide habitat for fish and wildlife.**" (emphasis added) Exh 31.

This Commission has previously recognized that the reach of SWRCB 75-58 does not extend to underground water sources. The Commission in the Elk Hills decision (99-AFC-1 at page 253) quotes the above definition in reaching this conclusion

Also, the definition contained in SWRCB 75-58 makes sense as the State has a high interest in protecting the rivers and streams that provide water for domestic, municipal, and agricultural uses and which provide recreation to the citizens of California and habitat for fish and wildlife.

Staff also relies heavily on current uses of the confined aquifer to substantiate their determination that the confined aquifer water should be considered "fresh". However, Staff's analysis regarding uses of the confined aquifer for agricultural and domestic purposes contains errors and inconsistencies. On FSA Page 4.9-11, Staff makes the statement that agricultural wells are "spaced approximately every quarter mile in this area." I know from personal observations and experience in this area that there is not even a well for every section, much less a well spaced every quarter mile. Wells are dispersed more broadly than as stated by Staff and there are fewer wells per unit area in the vicinity of the Project. Russell Freeman informed PEC that the Westlands Water District does not know which of the wells in the District are active. When URS tried to find active wells in the area to use as a sample for water quality, we were unable to find any active wells near the Project. The nearest well, one mile northeast from the project, was not active and Mr. Barry Baker, the well owner, indicated that the casing collapsed between 1993 and 1995 and the pump had been removed since then.

Staff notes on FSA Page 4.9-11 that there are residential buildings located near the project across Panoche Road. In this observation, Staff made the statement, "Any households in the area would use water from the confined aquifer for water quality reasons." I confirmed with Mr. Freeman that the residential and industrial facilities across Panoche Road from the Project use raw surface water provided by the Westlands Water District, not water from the confined aquifer. I am also aware from personal experience that the commercial center at Panoche Road and Interstate 5 uses surface water. I am aware of no residences that use the confined aquifer for domestic use if District surface water is available in the area. Notwithstanding the SWRCB determination in Resolution 88-63 that any groundwater with less than 3,000 ppm TDS is "suitable" for municipal or domestic use, there is virtually no demand in the area of the project for such uses from the confined aquifer and it is reasonable to conclude that the confined aquifer in the vicinity of the project will never become a desirable source of municipal or domestic water supply.

Staff is also inconsistent in their analysis of the suitability of the confined aquifer for sustained agricultural use. On pages 4.9-24 and 4.9-25 of the FSA, Staff notes that surface water is preferred over groundwater because of quality considerations. Staff further states that agriculture in the western San Joaquin Valley can no longer be economically sustained with groundwater alone and concludes "...regional soils are becoming increasingly saline, which makes soils increasingly toxic to crops (CDWR 2007B). Irrigation with groundwater will accelerate this process." The FSA further concludes that a reliance on groundwater is not probable because of groundwater and soil salinity. Staff has indeed made the point that the confined aquifer cannot be considered "fresh" because it is not suitable for long-term agricultural use.

10. Q. If, for some reason, the Commission is not convinced that the definition of "fresh inland waters" found in SWRCB 75-58 should apply, what should the Commission consider next?

A. If the Commission is not convinced that the definition found in SWRCB 75-58 should apply, the Commission should then consider if the alternate water supply is "environmentally undesirable" or "economically unsound" as described in the 2003 IEPR at page 41. This is the same test that appears in SWRCB 75-58.

11. Q. Considering SWRCB 75-58, how should the Commission conduct its analysis?

A. The policy contains seven principles, but only the first three are germane to the issue in this proceeding. The Commission should consider the facts of the case against these three principles, one at a time.

12. Q. The first principle contains a list of potential water sources, listing the highest priority first. How does the confined aquifer water fit within this priority listing?

A. Water from the confined aquifer certainly does not come from either of the first two sources, identified as: (1) wastewater being discharged to the ocean or (2) ocean. The next priority water is (3) brackish water from natural sources or irrigation return flow. The water from the confined aquifer is brackish as TDS levels are 840 to 1100 mg/L. The next category is (4) inland wastewaters of low TDS. The confined aquifer waters are not wastewater and are not of low TDS. The final category is (5) other inland waters, which, presumably, would include water of better quality than waters of high TDS.

There is evidence that this Commission has taken the same view in the past. The PEC proposed water supply has a TDS level of 840 to 1100 mg/L. A similar level (920-1100 mg/L) has been found by this Commission to be "marginally brackish" in a prior decision. (See Blythe II (02-AFC-1) Final Commission Decision, page 255).

13. Q. Staff prefers that the PEC use water from the semi-confined aquifer. Do you have any comments on this source and the SWRCB 75-58 first principle?

A. Yes. I believe water from the semi-confined aquifer also belongs in category 3 – brackish water from natural sources or irrigation return flow.

14. Q. The second principle states that "fresh waters for powerplant cooling will be approved... only when it is demonstrated that the use of other water supply sources or other methods of cooling would be environmentally undesirable or economically unsound." Do the Staff alternatives result in significant adverse environmental impacts?

A. I refer to the testimony of Ms. Fitzgerald for the environmental analysis. It appears that requiring the use of the semi-confined water would result in adverse, and unnecessary, environmental impacts related to taking additional prime agricultural land out of production and the generation of additional solid waste.

15. Q. Are the Staff alternatives economically unsound?

A. Yes. Most definitely. Guidance in the interpretation of this term appears in the Tesla Power Project (01-AFC-21) Final Decision, issued on June 16, 2004 - approximately six months after the adoption of the 2003 IEPR. "Economically unsound is defined as economically or otherwise infeasible. Feasible means capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors." (Pages 316-317)

There are seven separate areas for the Commission to consider in evaluating whether an alternate source of water is "economically unsound":

(1) Is the Project feasible with the alternate water proposal?

Mr. Chandler has indicated that the PEC is not feasible with the Staff's alternate water supply source. His testimony indicates that project cost and delay are the primary reasons.

(2) Can the Project be accomplished in a reasonable period of time? The testimony of Ms. Fitzgerald and the conclusions of Mr. Chandler indicate that the PEC could not be accomplished within a reasonable period of time if the Commission were to adopt either of Staff's alternate water sources. In this case, a reasonable period of time must be considered the time available to have a high degree of certainty that the terms of the PG&E power purchase agreement can be satisfied. As testified to by Mr. Chandler, any project approval conditions that result in extending the Final Decision (plus rehearing period) beyond January 31, 2008 could result in project cancellation, and, if beyond February 15, 2008, certain project cancellation.

(3) Do alternate sources of water make the PEC economically infeasible?
Most assuredly. Please refer to the testimony of Mr. Garrett where he testifies to the project cost penalty that would result from the adoption of the semi-confined aquifer water. Further, Mr. Chandler is testifying that these additional costs are incompatible with the terms of the PG&E power purchase agreements. In other words, the project is economically infeasible when considering the Staff alternative.

(4) Are there environmental penalties associated with the Staff's alternate water supply source?
Yes. Ms Fitzgerald testifies that there are negative environmental impacts that are unnecessary.

(5) Are there social factors to consider?
It does not appear that there any social considerations.

(6) Are there technical considerations?
Yes. Although the technical considerations, such as the lime softening system being incompatible with simple cycle operations, are reflected in the cost considerations as described by Mr. Garrett.

16 Q. The third principle requires the Commission to consider the "reasonableness of the water use when compared with other present and future needs for the water source and when viewed in the context of alternative water sources that could be used for the purpose". Is the proposed water use reasonable compared to present and future needs for the water?

A. Based on my knowledge and experience in the area, there is no demand for water from the confined aquifer for drinking or other municipal and industrial uses. Local farmers that have offices, shops, or homes in the area use surface water provided by Westlands Water District, as does the commercial center at Panoche Road and Interstate 5. All other communities in the Westlands Water District rely on surface water supplies from the District. The City of Mendota, which is adjacent to Westlands and approximately 18 miles northeast of the Project site, uses groundwater from a different aquifer, as noted in Mr. Jason Moore's testimony. Although agricultural users could use this water if no other higher-quality water is available, it is only used when surface water supplies are not available and the overall use is less than the sustainable yield within the Westlands groundwater sub-basin. Notwithstanding the uncertainties of surface water supplies on the west side of the San Joaquin Valley due to hydrologic variabilities and Delta pumping constraints, the confined aquifer is not usable as a long-term agricultural water supply, primarily due to its high salinity and potential impacts to soil salinity and crop production. Therefore, it is not likely that the confined aquifer will ever be used for anything other than emergency agricultural supplies in drought conditions. This conclusion was also reached by CEC Staff as noted in my response to question No. 9. The volumes of water required for the PEC will not deplete the confined aquifer to a significant degree and will not impact the availability of groundwater in the sub-basin for agricultural use as an emergency supply. In addition, water extracted from the confined aquifer does not result in any localized draw down and would not impact other local uses, if any. There is no present or foreseeable future need for this water that would be adversely impacted by PEC use of the confined aquifer.

17. Q. Have you reviewed the proposed enhancement program that PEC has negotiated with Westlands?

A. Yes, I have and offer the following comments:
This program supports the efforts of the Westlands Water District to conserve the high-quality surface water of the Central Valley Project. This water is in high demand for domestic, agricultural, and industrial uses. I believe that the proposed contribution of $1.5 million to the Westlands Water District Conservation program will fully offset the use of the confined aquifer.

18. Q. Do you have any concluding remarks.

A. Yes. My analysis of California water policy, based upon SWRCB 75-58 and the 2003 IEPR, indicates that the use of the water from the confined aquifer is consistent with state policy. Further, these policies are guidance for the CEC and not a prohibition on certain water sources. I conclude that a reasonable interpretation of current state policies and prior Commission decisions result in a determination that the confined aquifer is an appropriate source of water for the PEC.

19. Q. Are you sponsoring any exhibits in this proceeding?
A. Yes. I am sponsoring exhibits 31 and 32.

20. Q. Does that complete your testimony?
A. Yes, it does.