STATE OF CALIFORNIA

Energy Resources Conservation
And Development Commission

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In the Matter of:	)	Docket No. 02-AFC-01
	)	
Application for Certification	)	
for the BLYTHE ENERGY PROJECT, PHASE II	)	
	)	
	)	

Energy Commission Staff's Prehearing Conference Statement

On June 8, 2005 the Committee assigned to this proceeding issued a Notice of Prehearing Conference (Notice). In that document, the Committee requested parties to file Prehearing Conference Statements describing the nature of staff's intended testimony, and descriptions of any potential legal issue and any factual evidence potentially in dispute no later than June 24, 2005. This document contains Energy Commission Staff's (staff) responses to the information requested in the Notice.

Staff's written testimony will consist of:

- Final Staff Assessment (FSA) filed on April 29, 2005,
- the Soil And Water Resources Final Staff Assessment Technical Report filed on June 2, 2005, and
- Staff's Supplemental Testimony dated June 24, 2005, filed with this document.

To date, staff is the only party to this case that has filed formal, written testimony. Staff requests that the other parties be directed to file their testimony no later than July 5, 2005. Without the applicant's testimony, staff can only offer its best guess as to which topic areas are in dispute based on discussions with the applicant and other parties at workshops. On the basis of those discussions, together with the issues raised in staff's

Proof of Service (Revised 6-23-05) filed with original.
Mailed from Sacramento on 6-24-05

filed testimony, staff believes that the following topic areas will be in dispute and will likely need to be adjudicated:

- Biological Resources,
- Land Use,
- Soil and Water Resources,
- Traffic and Transportation,
- Transmission System Engineering, and
- Alternatives.

Staff's testimony and understanding of the legal and factual issues in these topic areas are summarized below. Staff awaits the applicant's and other parties' statements to learn exactly what dispute, if any, they have with staff's testimony in these or any other areas.

Biological Resources

Witness: Natasha Nelson

Nature of staff's testimony: Blythe Energy Project, Phase II's (BEP II) proposed evaporation pond would contain high, toxic levels of selenium and sodium similar to levels recently measured in Blythe Energy Project's (BEP I) existing ponds. Due to the scarcity of still water in the area, migratory birds and other protected wildlife would be drawn to BEP II's evaporation pond to feed, drink, roost, or nest and would be directly impacted by the high levels of contaminants found therein. Staff has proposed a condition of certification that would eliminate this impact and ensure compliance with the Migratory Bird Treaty Act (MBTA) and other LORS by requiring the use of a zero-liquid-discharge-to-solids system and eliminating use of the evaporation pond.

Issues: The proposed evaporation pond presents a significant adverse impact on birds and would make the project noncompliant with the MBTA and Fish and Game Code section 3513 which prohibit the harming, even unintentional and inadvertent, of migratory birds, as well as Fish and Game Code sections 3503, 3503.5, and 3505 which protect other species observed at the proposed site. The birds and other wildlife currently observed using the BEP I evaporation ponds are species protected by these LORS, and are highly likely to be attracted by BEP II's proposed evaporation pond. Replacing the proposed evaporation pond with a zero-liquid-discharge-to-solids system is feasible, would reduce the impact to less than significant, and would ensure the project will be compliant with LORS and the Energy Commission's 2003 Integrated Energy Policy Report. Both the U.S. Fish and Wildlife Service and California Fish and Game have expressed support for the elimination of the proposed evaporation pond. Thus, staff recommends the applicant be required to eliminate the use of the proposed evaporation pond and instead use a zero-liquid-discharge-to-solids system.

Land Use

Witness: David Flores

Nature of staff's testimony: BEP II's proposed site is located in a safety zone for the Blythe Airport. The Comprehensive Land Use Plan (CLUP) for the Blythe Airport prohibits any activity in a safety zone that would create light or reflection interference, generate smoke or water vapor, induce the gathering of birds, or create electrical interference. The CLUP lists power generating plants as an activity that would inherently pose these problems. Of specific concern are the attraction of birds to the evaporation pond and the generation of water vapor, in the form of both visible and invisible thermal plumes. Additionally, the CLUP prohibits 'any use which may otherwise affect safe air navigation'. The generation of thermal plumes can impact safe air navigation. The Riverside County Airport Land Use Commission (RALUC) has determined that the proposed location of BEP II is not consistent with the CLUP for the Blythe Airport. A city may overrule an airport land use commission's determination if the city makes specific findings that such an action is consistent with the purposes of protecting health, safety, and welfare and that it minimizes safety hazards in areas around the airport. (Pub.Utilities Code §21676.5.) The City of Blythe passed a resolution overruling the RALUC; however, neither the resolution, nor the city staff report supporting it, provided the necessary findings required for such an overrule. Staff agrees with the RALUC that the proposed project is inconsistent with the CLUP.

Issues: As an electricity generating plant located in one of the Blythe Airport's safety zones, BEP II is inconsistent with the CLUP. No modifications can be made to the proposed project that would resolve this inconsistency, save moving it to another location outside of the airport's safety zones. Staff can not recommend that the project be certified at the proposed location.

Soil and Water Resources

Witnesses: The following witnesses participated in writing various portions of staff's soil and water resources testimony. Depending upon the issues raised by the applicant or another party, most of them may not need to testify.

- **Linda Bond** (groundwater issues: water quality degradation, contaminates, Colorado River aquifer issues/accounting issues, decrease in Palo Verde Irrigation District's (PVID) agricultural return flows due to groundwater use, groundwater levels/well interference/pump damage, groundwater use in the area, PVID water use, response to comments),
- **John Kessler** (state water policy, impacts to other water users, Colorado River status, Southern California water supply issues, Alternative Cooling Study economic feasibility - alternatives analysis, PVID water use, Water Conservation Offset Plan (WCOP) evaluation, cumulative impacts to Colorado River, response to comments, differences between BEP I and II),
- **Jim Schoonmaker** (plant water use/heat and water balance, Alternative Cooling Study technical aspects - schematic of layout, cooling, process, and sanitary wastewater production and quality, zero liquid discharge-to-solid),
- **Richard Sapudar** (state water policy, Colorado River status, WCOP analysis, impacts to other water users, cumulative impacts to Colorado River, differences between BEP I and II),
- **Mark Lindley** (stormwater, erosion, sedimentation, the Drainage, Erosion, and Sedimentation Control Plan (DESCP) and the Storm Water Pollution Prevention Plan (SWPPP), retention basin, soils, WCOP erosion and best management practices (BMPs), evaporation pond),
- **Natasha Nelson** (general overview of water issues and policy),

Nature of staff's testimony: BEP II's pumping of groundwater would potentially cause upwelling or transport of groundwater with higher concentrations of naturally occurring minerals, resulting in further degradation of the water basin and, thus, creating a significant adverse impact to the environment and to the community of Mesa Verde, which is dependent upon this water source for drinking water. Additionally, because the large amount of groundwater used by BEP II would be replaced by Colorado River water from PVID's drains and canals, BEP II's use of groundwater would contribute to a significant adverse cumulative impact to the Colorado River water supply and its contractual users. The proposed use of water would also be an unreasonable use and, thus, inconsistent with the State Constitution and the state's water policy, as reflected in the Energy Commission's 2003 Integrated Energy Policy Report, because there are feasible alternatives, including dry cooling or using irrigation return flow from Rannell's Drain with a verifiable water conservation offset plan.

Issues: Due to BEP II's inconsistency with the State Constitution and the state's water policy, and its direct and cumulative impacts on water quality and supply, staff recommends the project be required to use one of two feasible alternatives: dry cooling or irrigation return flow from Rannell's Drain (in conjunction with a verifiable WCOP).

Traffic and Transportation

Witnesses:

- James Adams,
- Dale Edwards,
- Bill Arnold, and
- Will Walters.

Nature of staff's testimony: BEP II would be located within an airport safety zone approximately one mile east of the Blythe Airport, and closer to it than BEP I, and would generate both visible and invisible thermal plumes.   As has occurred at BEP I, these plumes would create turbulence which can result in significant adverse impacts to planes flying over the plant. The impacts could be cumulatively significant when added to the impacts resulting from BEP I. The California Department of Transportation (Caltrans) aeronautics division has expressed its expert opinion that a generating facility at this location is "not conducive to promoting a safe operational flight environment" and "may exacerbate existing concerns identified by pilots using the airport." (Letters from Austin Wiswell, Chief, Caltrans Division of Aeronautics, March 11, 2005 and March 24, 2004, respectively.) While staff has identified some mitigation measures to address the safety concerns, no mitigation measure or combination of measures, absent moving the project to another location, would adequately mitigate the impact. Therefore, staff can not recommend that the Commission certify the project at the proposed location.

Issues: The project as proposed will cause an unmitigable direct and cumulative adverse impact to aviation safety. Staff has not found, and the applicant has not identified, any mechanical changes that could be made to BEP II to mitigate its generation of thermal plumes and, thus, there appear to be no feasible mitigation measures available to adequately reduce the project's impacts to aviation safety. Therefore, staff can not recommend that the Commission certify the project at the proposed location.

Transmission System Engineering

Witnesses:

- Mark Hesters and
- Ajoy Guha

Nature of staff's testimony: As previously discussed by staff, there is currently insufficient information to describe in adequate detail BEP II's proposed transmission interconnection or to ensure that BEP II will conform with applicable transmission LORS and will not result in any significant adverse impacts under CEQA. The condition of certification proposed by the applicant does not ensure that these deficiencies will be remedied before construction is begun. Staff has proposed several conditions of certification to ensure that the interconnection configuration is adequately described and will comply with applicable LORS before construction of that portion of the project could begin.

Issues: In certifying a proposed project the Energy Commission must find that the project will be consistent with local, state, and federal laws, ordinances, regulations and standards and also must find that the project will not result in unmitigated significant adverse impacts under CEQA. (Cal. Code Regs., tit. 20, §1752(a); §1755(c).) Neither the information provided by applicant nor its proposed condition of certification support either of these findings. Staff has proposed several conditions of certification to ensure that the proposed interconnection is adequately described and will comply with applicable LORS before construction of that portion of the project could begin.

Alternatives

Witness: Susan Lee

Nature of staff's testimony: Staff has identified an alternative site, located off of the I-10 freeway and south of the SoCalGas compressor station, that could avoid the impacts identified at the proposed BEP II site while feasibly attaining the objectives of the project.

Issues: It is the policy of the State of California that projects should not be approved as proposed if there are feasible alternatives or mitigation measures available that would "substantially lessen the environmental effects of such projects." (Pub. Resources Code §21002; Cal. Code Regs., tit. 14, §15021(a)(2).) Certification of this project at the proposed site is not warranted because there is a feasible alternative site that would avoid the adverse impact to aviation safety.

DATED: June 24, 2005

Respectfully submitted,

____

LISA M. DECARLO
Staff Counsel

State Of California | The Resources Agency of California

Memorandum

Date : June 24, 2005
Telephone: (916) 654-4206
ATSS

To : John L. Geesman, Commissioner and Presiding Member
Arthur H. Rosenfeld, Commissioner and Associate Member

From : **California Energy Commission** - **BILL PFANNER**
1516 Ninth Street Energy Commission Project Manager
Sacramento, CA 95814-5512

Subject : **BLYTHE ENERGY PROJECT PHASE II (02-AFC-1) SUPPLEMENTAL TESTIMONY**

Attached please find staff's Supplemental Testimony to the Blythe Energy Project Phase II (BEP II) Final Staff Assessment (FSA) dated April 29, 2005 and the Soil and Water Resources Final Staff Assessment Technical Report published on June 2, 2005.

This Supplemental Testimony includes the following information:

Section I provides staff's responses to additional information in a May 4, 2005 letter from CAlifornians for Renewable Energy, Inc. (CARE) regarding cultural resources.

Section II provides staff's supplemental testimony regarding additional safety measures for Hazardous Materials Management, proposed Condition of Certification **HAZ-11**.

Section III provides revisions to Condition of Certification **WORKER SAFETY- 2.**

Section IV provides responses to the applicant's supplemental information titled Blythe Energy Phase II PSA Dry Cooling Economic Analysis and dated March 15, 2005.

Section V provides staff responses to the Palo Verde Irrigation District's comments on the FSA in their letter dated May 27, 2005.

Section VI provides staff's revised Transmission Systems Engineering (TSE) testimony with proposed conditions of certification. This testimony completely replaces the TSE testimony filed in the FSA on April 29, 2005.

Section VII provides Declarations and Resumes for staff involved in the preparation of the Soil and Water Resources Final Staff Assessment Technical Report published on June 2, 2005.

cc: Garret Shean
POS
List No. 7086, 7087, 7088

SECTION I

CULTURAL RESOURCES SUPPLEMENTAL TESTIMONY

CULTURAL RESOURCES

Supplemental Testimony

Gary Reinoehl

RESPONSE TO INTERVENOR'S COMMENT REGARDING CULTURAL RESOURCES

Comment: Additional information regarding cultural resources was provided by CAlifornians for Renewable Energy, Inc. (CARE) on May 4, 2005. The information states that the Blythe Energy Project II plant site is at the intersection of the East-West trail and the North-South trail that forms the four directions in the Creator Story. The letter also states that the Creator's chair is located one mile east of the Blythe Airport and the "Creator's image (geoglyphs) is two miles northeast of the runaway of the Blythe Airport." The letter indicates that traditional Native American elders and the Aztec Codex can substantiate the facts.

Response: The background research for the proposed project identified one trail on the Government Land Office maps that depicts 19th century features. That trail was about five miles east of the project area. No sensitive resource areas were identified by tribal representatives during either the Blythe Energy Project I or Blythe Energy Project II consultations with Native American tribes. Sensitive resources would include trails, geoglyphs, or other resources associated with the Creation story.

The Creator's chair is addressed in the Response to Intervenor's Comment in the Final Staff Assessment.

SECTION II

HARZARDOUS MATERIALS MANAGEMENT
SUPPLEMENETAL TESTIMONY

HAZARDOUS MATERIALS MANAGEMENT

Supplemental Testimony of Alvin Greenberg, Ph.D.

Staff has previously proposed Condition of Certification **HAZ-11** requiring that certain ammonia monitors and automatic door closures be installed in the anhydrous ammonia containment building and vent scrubber. As a result of discussions and training with the Blythe Fire Department, the Riverside County Fire Department, the Riverside County Hazardous Materials Response Team, and Florida Power and Light (owners/operators of Blythe Energy Project I), staff has determined that additional safety measures should be required for BEP II. These safety measures are the consensus recommendations of the above-referenced public safety agencies and Energy Commission staff. Florida Power and Light, the owner of BEP I is voluntarily implementing all of them.

Staff therefore proposes the following revisions to Condition of Certification HAZ-11:

HAZ-11 The project owner shall install an ammonia sensor on the discharge from the scrubber on the anhydrous ammonia refrigeration unit containment building that can be remotely read in the power plant control room and remotely read by a laptop computer operated by power plant personnel, the Blythe Fire Department and the Riverside County Fire Department. This sensor and all other sensors located inside the containment building shall be able to detect ammonia concentrations within a range of at least 10 to 20,0~~8~~00 ppm and shall be reported to the power plant control room on a real-time recordable basis. Additionally, the project owner shall:
1. install ~~the following equipment1.~~ power overhead doors in the containment building that close with a single press of an electronic actuator as well as manually;
2. install special end-caps that can be locked-outon any ammonia filter train assembly;
3. require that any maintenance or repair work on the anhydrous ammonia refrigeration unit is conducted only during normal daytime work hours;
4. require that maintenance or repair on any filter train be conducted only under lockout/tagout safety procedures;
5. provide that at least two doors that lead directly into the ammonia refrigeration unit containment building be equipped with safety glass windows so that all areas of the containment building can be viewed from the outside;
6. provide handheld ammonia vapor detectors and direct that they be used by workers whenever entering the ammonia refrigeration unit containment building; and
7. conduct joint training and exercises at least annually with the Blythe Fire Department, the Riverside County Fire Department, the Riverside County Hazardous Materials Response Team, the Blythe Police Department, and site staff.

Verification: At least sixty (60) days prior to delivery of anhydrous ammonia to the facility, the project owner shall provide final design drawings and specification for the above systems to the CPM for review and approval.

SECTION III

WORKER SAFETY AND FIRE PROTECTION SUPPLEMENTAL TESTIMONY

WORKER SAFETY AND FIRE PROTECTION

Supplemental Testimony of Alvin Greenberg, Ph.D.

Staff has previously proposed Condition of Certification **WORKER SAFETY-2** requiring that certain safety plans be submitted to Cal-OSHA Consultation Service. Staff learned on June 20, 2005 that Cal-OSHA no longer wishes to review or receive these plans.

Staff therefore proposes the following revisions to Condition of Certification **WORKER SAFETY-2**:

WORKER SAFETY-2 The project owner shall submit to the CPM a copy of the Project Operations and Maintenance Safety and Health Program containing the following:

- An Operation Injury and Illness Prevention Plan;
- An Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire Protection and Prevention Program (8 CCR § 3221); and
- Personal Protective Equipment Program (8 CCR §§ 3401-3411).

~~The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the Cal/OSHA Consultation Service, for review and comment concerning compliance of the program with all applicable Safety Orders.~~ The Operation Fire Protection Plan and the Emergency Action Plan shall also be submitted to the City of Blythe Fire Department and the Riverside County Fire Department for review and comment.

<u>**Verification:**</u> At least 30 days prior to the start of operation, the project owner shall submit to the CPM for approval a copy of the Project Operations and Maintenance Safety & Health Program. ~~It shall incorporate Cal/OSHA Consultation Service's comments, if any, stating that they have reviewed and accepted the specified elements of the proposed Operations and Maintenance Safety and Health Plan.~~ The project owner shall provide a letter from the City of Blythe Fire Department and the Riverside County Fire Department stating that they have reviewed and commented on the Operations Fire Protection and Prevention Plan and the Emergency Action Plan.

SECTION IV

SOIL AND WATER RESOURCES APPENDIX A WATER SUPPLY AND COOLING OPTIONS STUDY SUPPLEMENTAL TESTIMONY

Soil and Water Resources APPENDIX A
Water Supply and Cooling Options Study

Supplemental Testimony of John Kessler

Background

The purpose of this testimony is to respond to the applicant's supplemental information titled Blythe Energy Phase II PSA Dry Cooling Economic Analysis and dated March 15, 2005 (BEP II 2005) and address whether it would be economically unsound for the applicant to implement either an alternative degraded water supply or cooling method consistent with state water policy. Staff has concluded that it is necessary to implement either an alternative degraded water supply or cooling method in order to avoid potential significant adverse impacts to groundwater quality or cumulative impacts to other users of the state's Colorado River water supply. These impacts can be avoided by BEP II using either dry cooling, or mitigated by utilizing as its water supply agricultural drain water from Palo Verde Irrigation District's (PVID's) Rannells Drain with either wet or hybrid cooling and a verifiably effective Water Conservation Offset Plan (WCOP). Dry cooling would have the additional benefit of accomplishing the highest water conservation possible, reducing annual water demands from an average of about 3,300 acre-feet per year (AFY) to about 100 – 150 AFY.

State Water Policy

The FSA Soil and Water Technical Section under Cumulative Impacts - Groundwater Derived From The Colorado River – State Water Policy summarizes the policies supporting conservation of fresh inland waters and defines the test for determining whether an alternative water supply or cooling method is economically sound.

Conservation of fresh inland waters is defined in reference to direction provided by the Constitution and Water Code and the following state policies:

1. The State Water Resources Control Board's Resolution 75-58 that specifies fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound (SWRCB Resolution 75-58);
2. The Warren-Alquist Act which reiterates state water policy to conserve fresh water and use alternative sources of water by stating "*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;" and*
3. The Energy Commission's 2003 Integrated Energy Policy Report which states when considering the siting of power plants, "*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 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." (underline emphasis added)

The concept of whether an alternative water supply or cooling method is economically unsound is further defined by the Energy Commission's 2003 IEPR Policy as being "economically or otherwise infeasible". On the other hand, an alternative water supply or cooling method would be considered economically sound if it were determined that it was economically or otherwise feasible.

The environmental effects of the proposed project and alternative water supplies and cooling methods are as summarized in SOIL AND WATER RESOURCES APPENDIX A Table 8 - Environmental & Economic Summary of Alternatives and the Proposed Project. The following discussion focuses on the economic feasibility issue.

Applicant's Economic Estimates are Within the Range of Staff's Estimates

In Appendix A of the FSA Soil and Water Technical Section, staff prepared an economic analysis to consider water supply and cooling costs as an increment of the total power production costs, and to bracket the range of costs. The economic analysis is summarized in SOIL AND WATER RESOURCES APPENDIX A Table 7 – Economic Summary of Alternatives & the Proposed Project. Staff concluded that if the project were to receive degraded water supply from Rannell's Drain combined with either wet or hybrid cooling, BEP II's cost of production would only increase by 0.3% and 2.5% respectively. Staff concluded that even the highest cost alternatives (both Dry Cooling alternatives) are reasonably comparable to the Proposed Project, and in the worst case would only increase BEP II's cost of production by about 3.5%.

The applicant has estimated that its average annual production costs will range from \$0.035/KWH - \$0.050/KWH (BEPII 2002 - AFC Table 6.0-3, Project Alternatives). The applicant supplemented its previous economic comparison of cooling alternatives as provided in Appendix 6.0 of the AFC with updated information in a letter to the Energy Commission's Project Manager dated March 15, 2005 and titled Blythe Energy Phase II PSA Dry Cooling Economic Analysis. Similar to staff's conclusion, the applicant also concluded in its economic analysis update that if it were to implement dry cooling, its cost of production would increase by about 3.5% (BEPII 2005).

Effects of Increasing BEP II's Cost of Production by up to 3.5%

In bracketing the range of costs for the feasible water supply and cooling alternatives, staff has estimated that in the worst case, BEP II's cost of production would increase by only $0.001/KWh. This would result in an increase in BEP II's annual production cost in the low range from $0.035/KWH to $0.036/KWH and in the high range from $0.050/KWH to $0.051/KWH as shown below in SOIL AND WATER RESOURCES APPENDIX A Table 9 – Effects of Alternative Water Supplies and Cooling Methods on BEP II's Cost of Production.

SOIL AND WATER RESOURCES APPENDIX A Table 9

Effects of Alternative Water Supplies and Cooling Methods on BEP II's Cost of Production

Project Water Supply & Cooling Method	Estimated % Increase above Proposed Project @ $0.035/KWh	Comparison in Cost of Production if Proposed Project is $0.035/KWh	Estimated % Increase above Proposed Project @ $0.050/KWh	Comparison in Cost of Production if Proposed Project is $0.050/KWh
Proposed Project	Not Applicable	$0.035	Not Applicable	$0.050
Alt. 2 - PVID Irrig. Return Water with Wet Cooling	0.3%	$0.035	0.2%	$0.050
Alt. 3 - PVID Irrig. Return Water with Hybrid Cooling	2.5%	$0.036	1.7%	$0.051
Alt. 4 - Dry Cooling	3.5%	$0.036	2.5%	$0.051
Alt. 5 - Dry Cooling & 50 MW Peaker	1.0%	$0.035	0.7%	$0.050

Cost of production includes all annual operating and maintenance (O&M) costs as well as amortization of all capital and project development costs including financing. The most significant variable affecting cost of production is natural gas prices, which can vary significantly over the life of the project. BEP II's cost of production is expected to be lower attributed to when natural gas prices are lower, and proportionately higher attributed to when natural gas prices are higher. Based on industry standards, the lower range of BEP II's estimated cost of production of around $0.035/KWh is expected to reflect current conditions and gas prices.

Profit Margin Effects from Higher Cost of Production

Implementation of an alternative water supply and/or cooling method would not affect BEP II's economic viability in relation to its ability to recover the cost of its investment and O&M costs. Instead, it could result in a slight reduction in its profits. This is evident by comparing BEP II's expected cost of production which staff believes would be in the lower part of its range near $0.035/Kwh considering current gas prices with the current power values, and realizing the margin between the two that would result in profit.
The value BEP II would receive for its power and its profitability is subject to the method of how BEP II would market its power. Some of the most common methods with their relative certainty, price volatility, availability and financial outlook are summarized in SOIL AND WATER RESOURCES APPENDIX A Table 10.

In every case and method for marketing power, it is expected that BEP II would recover its cost of production and earn profit. While gas prices will influence the value of power, considering the extent of California's generation resources that depend on natural gas as fuel, there is reasonable certainty that the more efficient combined cycle power plants will continue to earn profit despite potential gas price volatility. BEP II's cost of production is expected to be lower when natural gas prices are lower, and similarly higher when natural gas prices are higher. Energy prices are expected to similarly follow the trend of natural gas prices, and therefore maintain profitability for the more thermally-efficient combined cycled projects such as BEP II. In addition, BEP II could sell balance energy, capacity, and ancillary services to the ISO to supplement its electricity income.

SOIL AND WATER RESOURCES APPENDIX A Table 10

Characterization of Typical Methods for Marketing Power

Typical Power Marketing Methods	Term of Agree-ment	Risk & Price Volatility	Current Availability of Marketing Method	Financial Outlook & Terms
Purchase by DWR	10 years	Lower Risk – Purchase price varies according to fuel cost	No - New contracts are no longer available	Very Good – As an example during 2004 for Sempra Energy, base load energy was purchased at about \$0.068/KWh and On-Peak Energy at about \$0.087/KWh (Sempra 2001)
Purchase by Utility	10 years	Lower Risk – Provides price stability for term of agreement	Yes – Utilities such as Southern CA Edison are soliciting Requests for Offers for up to 1,500 MW of new generation in minimum blocks of 25 MW (SCE. 2005)	**GOOD -** Bid prices are unknown, but provide profit and financial certainty to the generator; Extent of profit is subject to energy price forecasts vs. real-time market conditions
ISO Imbalance Energy	Real-Time	Moderate Risk – Price stability is not certain for long term, but is expected to remain competitive for combined cycle units that are more economic than older steam generation units	Yes – However, marketing opportunities are more limited	Good - Monthly average incremental energy values varied from \$0.060 to \$0.080/KWh during 2003 and 2004 (CAISO 2005)
Spot Energy	Real-Time	High	Yes	Monthly average energy values varied from \$0.037 to \$0.052/KWh during 2003 and 2004 (Economic Insight 2004)

1) Under Sempra Energy's DWR Contract, Base Load Energy is purchased at (Gas Price x 7.5 MMBtu/MWh) + \$26/MWh; Using the 2004 average natural gas price of \$5.62/MMBtu, Base Load Energy is purchased at \$68/MWh or \$0.068/KWh;
2) Under Sempra Energy's DWR Contract, On-Peak Energy is purchased at (Gas Price x 10.0 MMBtu/MWh) + \$31/MWh; Using the 2004 average natural gas price of \$5.62/MMBtu, On-Peak Energy is purchased at \$87/MWh or \$0.087/KWh (Sempra 2001);
3) Per California ISO's 2004 Annual Report on Market Issues and Performance, average natural gas prices during 2004 were \$5.62/MMBtu (CAISO 2005)

Conclusion

It is staff's position that the minimal increase in production cost resulting from implementing an alternative water supply and/or cooling method would not compromise BEP II's economic viability. While the increase in cost of production would likely cause a slight reduction in BEP II's profit margin, it would not affect the project's economic feasibility.

As further evidence of the economic feasibility of implementing an alternative water supply and/or cooling method, including the most costly alternative for BEP II – Dry Cooling, some of the state's merchant power competitors already rely entirely on dry cooling. These include the currently operating Crockett and Sutter Power Plants, and Otay Mesa, which is under construction.

REFERENCES

BEP II 2005. Supplemental Response to California Energy Commission Preliminary Staff Assessment, Blythe Energy Project Phase II PSA Dry Cooling Economic Analysis, Caithness Blythe II LLC, March 15, 2005

CAISO 2005. California Independent System Operator, 2004 Annual Report on Market Issues and Performance, April 2005.

Economic Insight 2004. Economic Insight, Inc., Energy Market Report, www.econ.com/emrindex.html

Sempra 2001. Sempra Energy Resources. Energy Purchase Agreement between Department of Water Resources and Sempra Energy dated May 4, 2001.

SCE 2005. Southern California Edison. Request for Offers of New Generation Resources dated April 22, 2005. http://www.sce.com/AboutSCE/Regulatory/newGenRFO/

SECTION V

SOIL AND WATER RESOURCES
FINAL STAFF ASSESSMENT
TECHNICAL REPORT
SUPPLEMENTAL TESTIMONY

SOIL AND WATER RESOURCES
FINAL STAFF ASSESSMENT TECHNICAL REPORT

Supplemental Testimony of Linda Bond

This additional testimony was prepared to address issues either raised or in-progress during or after the FSA was being finalized and published. Staff has attempted to address outstanding issues in the interest of completeness to the extent possible. This document provides a response to comments received in a letter dated May 27, 2005 from the Palo Verde Irrigation District on the FSA, and subsequent conference call with the PVID held on June 15, 2005.

RESPONSE TO COMMENTS

PVID'S FSA COMMENTS

Staff has prepared the following responses to PVID's comments to the FSA provided in its letter dated May 27, 2005 (PVID, 2005a):

Comment 1: PVID water rights. PVID reviews some of the terms of the district's 1933 contract with the USBR for the use of Colorado River water and the effect of project groundwater pumping on PVID return water flow in the Rannells drain.

> **Staff Response:** Staff does not identify any disagreement between PVID's comment and the FSA.

Comment 2: Water Conservation Offset Program (WCOP). PVID states that it is not taking a position on the WCOP, but provides a description of conditions it would and would not support if a WCOP were implemented. PVID does not support the permanent retirement of land, which is one of the alternatives of the WCOP proposed by the applicant.

> **Staff Response:** Staff did not specifically oppose the alternative included in the applicant's WCOP proposal that called for permanent land retirement. However, the final plan for the WCOP has not been approved and would be submitted during the compliance phase of the project. At the time of submittal PVID will be able to review and comment on the WCOP.

Comment 3: Average Crop-Water Consumption. PVID disagrees with the average crop-water consumption value of 4.2 acre-foot per acre, which was proposed in the applicant's WCOP. PVID states that the historic consumption rate in the valley ranges from 4.8 to 5.0 acre-foot per acre.

> **Staff Response:** Staff notes that the consumption value of 4.2 acre-foot per acre has been accepted by the USBR and was used in the PVID-Metropolitan Water District water transfer contract, and, thus, was adopted and applied by staff. Staff is willing to

consider PVID's alternative consumption values but recommends any revision of consumption values should be reviewed and approved by both the USBR and the Colorado River Board of California during the compliance phase of the project.

Comment 4: Hydraulic Connection of Mesa Groundwater and Rannells Drain Water to Colorado River Flows. PVID reviews the local hydraulic conditions that demonstrate the continuity of flow and asserts that the Colorado River is the common source of water for groundwater and drainwater throughout the Palo Verde region.

Staff Response: Staff does not identify any disagreement between PVID's comment and the FSA.

Comment 5: Saline Degradation Caused by Groundwater Pumping. PVID disagrees with staff's assessment that project pumping is likely to cause irreversible saline degradation of the mesa aquifer. Although PVID provides a description of its understanding of local groundwater dynamics, it did not provide specific data sources or data to support the opinion presented in its Comment 5.

Staff Response: PVID asserts that groundwater pumping on the mesa improves groundwater quality under the mesa. Staff has reviewed PVID's comments on mesa groundwater quality dynamics, however all of the water quality data from mesa wells analyzed by staff to date indicates a steady increase in TDS over time in the mesa aquifer, as described in FSA testimony.

In response to receiving PVID's letter, staff conferred with PVID for clarification of its groundwater quality assessment and requested that PVID provide information and data that supports its assessment (PVID, 2005b). In response to staff's request, PVID stated that there is very little information on groundwater quality data for the mesa. PVID said the best source of information for the mesa is the 1973 USGS report on regional geohydrology (Metzger, 1973) and the USGS well information on the internet. These USGS data are the primary sources used by staff to develop its FSA testimony. However, PVID used two other sources of information to develop its assessment that had not been previously identified or used by staff. The first is a report developed for the USBR entitled "Reduction of Salt Loading to the Colorado River from PVID" by Bookman-Edmonston Engineering Inc (August 1976). The second is PVID's observations of water quality changes in drain water in the valley. PVID has documentation of these changes for PVID's Anderson agricultural drain located in the southwest portion of the Palo Verde Valley, which is available as a graph. PVID agreed to provide staff with a copy of the report and a graph of the drain salinity data.

During staff's telephone conference call with the PVID, staff requested copies of the water quality testing data from the Mesa Verde community well or the City of Blythe wells, which are mentioned in PVID's comments. Although PVID had not used any data from these wells, they suggested that water quality data might be obtained from the county water agency that manages the community well and from the City of Blythe, which manages the city water wells. Staff will attempt to obtain these records prior to evidentiary hearings, if possible.

Staff plans to further evaluate the potential for proposed project groundwater pumping to cause water quality changes in the mesa based on PVID's comments and the additional water quality data identified above. Staff can provide supplemental testimony on its findings for the evidentiary hearings.

Comment 6: Source of Selenium in Evaporation Pond Water. PVID asserts that presence of selenium in BEP I evaporation pond water is evidence that the source of groundwater produced by BEP I wells is PVID irrigation water diverted from the Colorado River and transported by underflow from the Rannells drain because selenium was not reported in pre-1960 mesa water well analyses.

Staff Response: Staff does agree with PVID that project groundwater pumping at the BEP I and BEP II would induce underflow of water from the Rannells drain and from percolated irrigation water from the valley into the mesa towards the projects wells, as stated in the FSA. However, staff does not have sufficient evidence to support PVID's conclusion that selenium in evaporation pond water is an indicator of the transport of Colorado River irrigation water to the groundwater produced by BEP I. The fact the USGS reporting on water quality from the 1960's does not mention selenium most likely only indicates that selenium was not included in the chemical analyses performed at that time.

Furthermore, staff concurs with the USGS assessment that almost all of the water contained in the aquifer beneath the Palo Verde Mesa is derived from the Colorado River. Groundwater in the mesa is derived from overland flow and underflow from the Colorado River during the formation of Colorado River valleys and the period prior to human modification of the natural flow regime, as well as from underflow from Rannells drain and from agricultural irrigation on the mesa, as PVID notes. Therefore, unless the Colorado River did not contain selenium until after the valley aquifer formed or more recently, selenium could not be used as an indicator of the transport of valley irrigation water into the portion of the aquifer underlying the mesa.

Comment 7: Description of Regional Water Levels. PVID suggests that the FSA should provide a more detailed description of the water levels in the river and the aquifers.

Staff Response: Staff does not identify any conflict between PVID's comment and the information provided in the FSA. Although the introductory text on page 4.9-2 states that the groundwater system in the Palo Verde region is predominated by the Colorado River, the detailed discussion in the Soil & Water Technical Report published on 6/2/2005 explains in detail that irrigation water diverted from the Colorado River by PVID controls the valley groundwater system, as well as explaining the interaction between the Rannells drain and groundwater beneath the mesa.

Comment 8: Fresh Water Aquifer. PVID disagrees with staff's water quality characterization of the Palo Verde Mesa aquifer as a fresh water aquifer. PVID asserts that if better quality groundwater in the mesa, it occurs because of underflow of PVID irrigation water from Rannells drain.

Staff Response: While staff agrees with PVID that water quality in the mesa is often poor, owing to TDS concentrations, staff has concluded that it should be considered a fresh water source because it is a source of drinking water to the Mesa Verde community and to private well owners on the Mesa. In addition, staff's review of water quality in the mesa in the 1960's indicated a wider range of salinity, including better quality water, than PVID notes in its comments. Finally, staff plans to review PVID's comments on the effect of irrigation water on mesa water quality, which PVID described in more detail in Comment 5.

Comment 9: Colorado River Board (Items 4 and 8 on page 4.9-17). PVID disagrees with the Colorado River Board's position on BEP II water use.

Staff Response: In item 4 on page 4.9-17, staff reports that the Board states that if BEP II's proposed groundwater is unmitigated if would reduce Colorado River water supplies to junior California water rights holders. PVID's disagreement with this position is not clear.

In item 8 on page 4.9-17, staff reports that the Board states that BEP II groundwater use will be unauthorized unless it has a water supply agreement with PVID. However, PVID comments that "the use of water by Blythe Energy II will be addressed under current PVID regulations," which implies some agreement or permitting will occur between PVID and the BEP II project, something that is not known at this time.

Comment 10: Fire Protection. PVID's comment addresses Worker Safety and Fire Protection testimony. PVID asserts that BEP II will have a right to use groundwater for fire protection based on PVID's Colorado River water right.

Staff Response: It is staff's opinion that groundwater use for fire protection would pose a negligible potential adverse impact and does not disagree with PVID on the project's use for groundwater for fire control.

Comment 11: Water Issues for Alternative Site Locations. PVID asserts that all local (alternative) sites would have the same water use and groundwater issues.

Staff Response. Staff does not identify any disagreement between PVID's comment and the FSA for a wet cooled project. However, staff has determined that pending resolution of the airport safety issue that exists with either wet or dry cooling at the proposed site, the use of dry cooling would essentially avoid these groundwater issues at the proposed site or any alternative site that would use groundwater derived from the Colorado River.

REFERENCES

CRBRWQCB 2005. Personal communication between Alvin Greenberg representing the California Energy Commission and Abdi Haile of the Colorado River Regional Water Quality Board. June 2, 2005.

PVID. 2005a. Letter to Roger E. Johnson of the California Energy Commission from Roger Henning of the Palo Verde Irrigation District. May 27, 2005.

PVID. 2005b. Record of Conversation, between Roger Henning of Palo Verde Irrigation District, and Linda Bond and Rich Sapudar of the California Energy Commission: Subject: PVID's Comment (5) on FSA discussion of saline degradation caused by groundwater pumping. June15, 2005

SFBRWQCB 2001. "Application of Risk-Based Screening Levels (RBSLs) And Decision Making to Sites With Impacted Soil and Groundwater", California Environmental Protection Agency, Regional Water Quality Control Board, San Francisco Bay Area Region.

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SECTION VI

TRANSMISSION SYSTEM ENGINEERING

TRANSMISSION SYSTEM ENGINEERING

Testimony of Ajoy Guha, MSEE, PE and Mark Hesters

SUMMARY OF CONCLUSIONS

The Blythe Energy Project Phase II Description is inadequate. The California Environmental Quality Act (CEQA) requirement to identify the "whole of the action" cannot be met without an adequate project description.

The Commission has permitting authority up to and including the plant switchyard, outlet line, and termination facilities. The applicant proposes to connect the Blythe Energy Project Phase II (BEP II) to the existing Buck Boulevard Substation in the Western Area Power Administrations (Western) service territory. The applicant has not provided an accurate description of the facilities and substation modifications required to connect the BEP II to the Buck Boulevard substation.

1. The applicant has not provided the approved interconnection studies that staff relies on to identify the transmission facilities required to reliably connect a proposed project like BEP II to the existing transmission network. Without these approved studies staff is unable to determine whether or not facilities beyond the first point of interconnection are required and thus is unable to determine if the project complies with CEQA.

With the available information, staff cannot identify the direct or cumulative environmental impacts. For the reasons cited above and explained further below, staff recommended that the Commission not consider approval of the BEP II project until the required information is provided. Staff's recommendation was contained in the 'Motion to Compel Applicant to Submit Certain Information on Proposed Transmission Interconnection Configuration', May 9, 2005, (Motion to Compel) which was subsequently denied by the Committee. While staff retains its position that the information identified in the Motion to Compel should be provided prior to certification, staff is recommending the Conditions of Certification **TSE-1** through **TSE-9** in the event the Commission ultimately approves the project.

INTRODUCTION

This Transmission System Engineering (TSE) analysis examines whether or not the transmission facilities associated with the proposed project conform to all applicable LORS required for safe and reliable electric power transmission and whether or not the applicant has accurately identified all interconnection facilities required for connection of the project to the electric grid. A definition of technical terms is provided in the TSE Attachment 2, at the end of this section.

Staff's analysis evaluates the power plant switchyard, outlet line, termination and downstream facilities identified by the applicant, California Independent System Operator (CA ISO), Western and the staff. Staff's analysis would normally provide "standard" proposed conditions of certification to ensure that the project complies with applicable LORS during the design review, construction, operation and potential closure of the project. However, the project interconnection facilities are infeasible because the applicant did not account for changes to the Buck Boulevard substation proposed by the Blythe Energy Project Transmission Line (BEPTL) modification plan[1] which is ahead in the generation/transmission queue[2] (CA ISO, 2003a). Thus, staff is proposing non-standard conditions of certification based upon the issues raised in this testimony.

Unlike other applications for certification, since the Western system is not a part of the CA ISO grid, the CA ISO is not responsible for the BEP II generator interconnection to the Western System (Buck Boulevard Substation). The staff, therefore, has the increased responsibility to evaluate the system reliability impacts of the project and provide conclusions and recommendations to the Commission. However, the CA ISO is still responsible for making sure that there are no adverse impacts on the CA ISO grid due to interconnecting the BEP II generation project to the Western system. At this time without a System Impact Study (SIS) that has the queue projects properly modeled by the transmission owner (TO), the CA ISO cannot provide a review and conclusions.

Furthermore, under CEQA, the Energy Commission must conduct an environmental review of the "whole of the action," which may include facilities not licensed by the Energy Commission (California Code of Regulations, tit 14, §15378). Therefore, the Energy Commission must identify and evaluate the environmental effects of construction and operation of any new or modified transmission facilities required for the project's interconnection to the electric grid, as well as any facilities beyond the project's interconnection with the existing transmission system that are required as a result of the power plant interconnection to the California transmission system. Facilities required for interconnection of the project and those that are a reasonably foreseeable consequence of the project beyond the project's interconnection with the existing system are defined as "downstream and analyze facilities". Applicants are required to provide enough information on a project for the Energy Commission to conduct an analysis of the "whole of the action". Staff relies partially on the input from the CA ISO and Western in its identification of downstream facility requirements.

Caithness Blythe II, LLC (applicant) filed an AFC with the California Energy Commission to construct a nominal 520-megawatt (MW) natural gas-fired combined cycle generating facility to be located about 5 miles west of the City of Blythe near Interstate 10 and the Blythe Airport (BEP II, 2002a, Application for Certification, 2-20-02). The applicant proposes to connect their BEP II project to Western's existing Buck Boulevard Substation where the Blythe Energy Project Phase I (BEP I) is presently interconnected. According to the AFC, BEP II was planned to be on-line in the summer of 2006 (BEP II, 2002h), however this date is infeasible given the status of the siting process and construction

[1] The BEPTL modification plan was filed by Blythe Energy on October 12, 2004, as a petition to amend the Blythe Energy project to build transmission modifications from the Buck Boulevard Substation as follows: a) a 67.4 mile single circuit 230 kV line from the Buck Boulevard Substation to the Julian Hinds substation, or b) a 6.7 mile 230 kV single circuit line to a new Midpoint Substation with connection to the existing DPV1 500 kV line or c) both transmission modifications. Significant modifications to the Buck Boulevard substation are required.

[2] In the generator interconnection paradigm per the Federal Energy Regulatory Commission's (FERC) requirements an Interconnection Application is filed, the applicant's facilities are described, the interconnection point is identified, a System Impact Study Agreement is signed and fees are paid. The CA ISO's tariff provides generally that an applicant secures a place in the queue for new projects when their application is received. Until recently the applicant failed to submit an Application for Interconnection to Western and SCE in a timely manner. As a result the queue position of the BEP II project is behind that of the proposed DPV2 line and the BEP I BEPTL plan.

timelines. At this time staff believes that the earliest the plant could come on-line would be in mid to late 2008 depending on the new transmission option(s).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

TSE Table 1 provides a brief list of the LORS that apply to this analysis. A detailed description of these LORS is provided in TSE Attachment 1.

TSE Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Regional	
North American Electric Reliability Council (NERC) Planning Standards	Principles designed to insure the adequacy and security of the transmission network
Western Electric Coordinating Council (WECC) Reliability Criteria	Insure continuity of load service and protection of the interconnected grid.
National Electric Safety Code 1999 (NESC	Provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation
Western, General Requirements of Interconnection	Requirements for Interconnection, additions and modifications to Western grid.
State	
California Public Utilities Commission (CPUC) General Order (GO) 95	Rules for overhead line construction
CA ISO/FERC Electric Tariff	Provides guidelines for transmission additions/upgrades within the CA ISO controlled grid.
CA ISO Reliability Criteria	Incorporate NERC and WECC standards and some additional requirements.

EXISTING FACILITIES AND RELATED SYSTEMS (SETTING)

The existing transmission facilities in the vicinity of the BEP II project area and generating plant and facilities which deliver power to the Devers Substation include the following (See **TSE Figure 1** attached):

- Buck Boulevard 161/230 kV Substation owned by Western (approved by the Commission in 2001 when the BEP I project was approved).
- Blythe 161 kV Substation. This Western substation is connected to the Buck Boulevard 161/230 kV Substation by an 1800 foot 161 kV single circuit line (the line was approved by the Commission in 2001 when BEP I was approved).
- Devers-Palo Verde (DPV1) line owned by Southern California Edison (SCE).
- Parker-Gene 230 kV line owned by Western.

- Gene-Camino-Eagle Mountain-Julian Hinds 230 kV line owned by Metropolitan Water District (MWD) and operated by SCE.
- Julian Hinds-Mirage-Devers 230 kV Line owned by SCE.
- Parker-Harcuvar-Hassyampa 230 kV line owned by Bureau of Reclamation (BOR) and operated by Western.
- Coachella-Ramon-Mirage 230 kV line owned by Imperial Irrigation District (IID).
- Coachella-Devers 230 kV line: the Coachella-Mirage section owned by IID and the Mirage-Devers section owned by SCE.

The Blythe Substation, which is a part of Western's "South of Parker" transmission system, is connected with the following:

1. Blythe-Knob 161 kV line owned by Western.
2. Parker-Blythe 161 kV line owned by Western.
3. Parker-Headgate-Blythe 161 kV line owned by Western.
4. Niland-Blythe 161 kV line owned by Imperial Irrigation District (IID).
5. Path 59: Interconnection between Western and SCE systems via Path 59 which is a bus-tie between Western's Blythe Substation and SCE's Blythe (Blythesc) Substation.
6. Eagle Mountain-Blythesc 161 kV line owned by SCE.

Western's Blythe and Parker Substations receive significant hydropower from Western's Hoover, Davis and Parker Dams, and transmit power to Arizona and the lower Colorado River areas served by IID and Arizona Public Service (APS).

TRANSMISSION OPTIONS

In view of limited transmission capacity in the "South of Parker" transmission system and in the existing DPV1 line, staff believes that accommodating the power output from the existing 520 MW BEP I plant and from the proposed 520 MW BEP II plant to the CA ISO grid warrants consideration of the following major transmission plan options:

a. A new bulk 500 kV transmission line or a double circuit 230 kV line from Buck Boulevard Substation to SCE's Devers (or Mirage) Substation similar to the proposed Desert Southwest Transmission Project (DSWTP) being sponsored by IID and Desert Southwest Power (DSP)[3].

b. Construction of a Devers-Harquahala 500 kV line (generally known as the Devers - Palo Verde 2 line or DPV2 currently proposed by SCE), with a Midpoint Substation at Blythe (with provision for BEP II interconnection at the Midpoint Substation) instead of going directly to Devers. Construction of the BEP I sponsored BEPTL

[3] A 500 kV DSWTP line from the Buck Boulevard Substation to the Devers Substation would parallel SCE's proposed Devers-Palo Verde #2 project. The proponents of the DSWTP are negotiating with SCE in order to include the DSWTP as part of the DPV2 project.

plan (which would deliver power from BEP I plant only and would not accommodate output from BEP II).

c. Construction of the BEP I sponsored 230 kV transmission line from Buck Boulevard Substation to Julian Hinds Substation and reconductoring of the existing 230 kV line between Julian Hinds and Mirage Substation to achieve higher capacity (will deliver power from the BEP I plant only).

The BEPTL modification plan was filed by Blythe Energy on October 12, 2004, as a petition to amend the Blythe Energy project (BEP I) to build transmission modifications from the Buck Boulevard Substation as follows: a) a 67.4 mile single circuit 230 kV line from the Buck Boulevard Substation to the Julian Hinds substation, or b) a 6.7 mile 230 kV single circuit line to a new Midpoint Substation with connection to the existing DPV1 500 kV line or c) both transmission modifications. Significant modifications to the Buck Boulevard substation are required. The BEPTL plan will deliver power only from the BEP I plant to the CA ISO grid.

In staff's view, the proposed DSWTP 500 kV line between the Buck Boulevard Substation or Midpoint Substation and the Devers Substation would provide the most comprehensive and expedited solution to relieving the inadequate transmission capacity between the Blythe area and the CA ISO grid. The DSWTP has the potential capability to have a lower overall cost per megawatt of transmission capacity than other new transmission options being pursued, and also could minimize environmental impacts in the BLM designated transmission corridor by eliminating the short-term need for other lines in the corridor. The DSWTP line likely is capable of delivering power from both the BEP I and BEP II plants (1,040 MW) to the CA ISO grid and would unload power flows in the "South of Parker" lines of the Western system.

PROJECT DESCRIPTION

Although staff provides the following project description, the applicant's proposed interconnection facilities as described below are not feasible if the BEPTL project is constructed. The project interconnection facilities are infeasible because the applicant did not account for changes to the Buck Boulevard substation proposed by the BEPTL modification plan which is ahead in the generation/transmission queue (CA ISO, 2003a).

The BEP II site would be located approximately 2,000 feet southwest of the Western Buck Boulevard 161/230 kV Substation. The BEP II would consist of two combustion turbine generators (CTG), each with an output of approximately 170 MW and one 180 MW steam turbine generator (STG), for a total plant nominal output of 520 MW. Each of the generating units would be connected to a dedicated 225 MVA, 16/500 kV step-up transformer and the high voltage terminals of each transformer would be connected to the new BEP II 500 kV Integration Switchyard switch bays by overhead conductors (See **TSE Figures 4 & 5**, attached).

BEP II INTEGRATION SWITCHYARD

The new BEP II 500 kV integration switchyard would have four switch bays with 500 kV circuit breakers. The high voltage transformer terminals of two CTG and one STG units would be connected by overhead conductors to three switch bays. The fourth bay would be connected to a 500 kV 2-2156 Aluminum Conductor Steel Reinforced (ACSR) interconnecting line to a new 500 kV substation to be built as an expansion of the existing Buck Boulevard Substation within its fence line. Since the diagrams provided by the applicant are conceptual and have no specific details, staff's description is therefore, preliminary. The applicant would design, build, own and operate the BEP II integration switchyard.

TRANSMISSION INTERCONNECTION FACILITIES AND BUCK BOULEVARD 500 KV SUBSTATION

The new BEP II 500 kV integration switchyard is proposed to be interconnected to the existing Western Buck Boulevard 161/230 kV Substation by building a new approximately 2500 foot 2-2156 ACSR conductor 500 kV transmission line to be built by Western or the applicant. The line would carry the full generation output of the BEP II to the Buck Boulevard 500 kV Substation to be built by Western within the fence line of the existing 161/230 kV substation. The new Buck Boulevard 500 kV Substation would have three switch bays with 500 kV circuit breakers. The proposed 500 kV substation would be connected to the existing Buck Boulevard 161/230 kV Substation by installing a 400 MVA 500/230/161 kV step-down dual voltage transformer in the new substation. The third 500 kV switch bay would be used to connect the new 118-mile DSWTP 500 kV line to SCE's Devers Substation. Since the diagrams provided by the applicant are conceptual and have no specific details, and Western has not yet confirmed the layout plan for interconnecting facilities at the Buck Boulevard Substation, staff's description is therefore, preliminary (See **TSE Figures 4 & 5**, attached).

DSWTP 500 KV TRANSMISSION LINE

The new 118-mile 500 kV line from Buck Boulevard Substation to Devers Substation is sponsored by IID and DSP as the DSWTP line. The DSWTP line is proposed to provide for additional power flow from the BEP II generation unit or from the combined generation output from both BEP I and BEP II to the CA ISO grid. It would serve as the project's primary transmission service (See **TSE Figures 3 & 4**, attached). No information has been received by the staff directly from SCE or Western describing the specific details of the new facilities and/or modifications involved in the SCE and Western substations to accommodate the new line. Also, the BEP I owner has not agreed that its generating units will remain connected to the Buck Boulevard Substation as described by BEP II.

ALTERNATIVE TRANSMISSION INTERCONNECTION FACILITIES

The applicant initially considered four transmission interconnection alternative options as follows (BEP II, 2003c):

1. Option 1: A double circuit 80-mile 230 kV line with 2-1272 ACSR conductor from the BEP II 230 kV switchyard to IID's Midway 230 kV Substation. The alternative also included a new 230 kV line with 2-1272 ACSR conductors from IID's Highline 230 kV Substation to the El Centro switching station.
2. Option 2: A double circuit 80-mile 230 kV line with 2-1272 ACSR conductors from the BEP II 230 kV switchyard to IID's Midway 230 kV Substation.

3. Option 3: A double circuit 120-mile 230 kV line with 2-2156 ACSR conductors from the BEP II 230 kV switchyard to SCE's Devers 500/230 kV Substation.
4. Option 4: A 120-mile 500 kV line with 2-2156 ACSR conductors from the BEP II 500 kV switchyard to SCE's Devers 500/230 kV Substation.

As a result of the BART feasibility and screening study, the applicant chose the preferred transmission option over the preceding alternatives as: A 118-mile 500 kV line (DSWTP line) with 2-2156 ACSR conductors from the Buck Boulevard 500 kV Substation to SCE's Devers 500/230 kV Substation, a 500 kV interconnection line from the BEP II 500 kV Integration switchyard to the new Buck Boulevard 500 kV Substation with a 500/230/161 kV step-down transformer at the new Buck Boulevard 500 kV Substation (BEP II, 2003f).

As previously discussed, staff understands that the applicant is pursuing with SCE other interconnection alternatives not presently described to the Commission. Staff believes those new alternatives include a termination on the DPV1 line or the proposed DPV2 line (CA ISO, 2005, DSP, 2005).

ANALYSIS AND IMPACTS

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

In a typical interconnection paradigm a System Impact Study (SIS) for connecting a new power plant to the existing power system grid is performed by the transmission owner to determine the required transmission facilities to interconnect the plant to the grid, and identifies downstream transmission system impacts and their mitigation measures. The SIS assures conformance with system performance levels as required by utility reliability criteria, NERC planning standards, NERC/WECC reliability criteria and CA ISO reliability criteria. The SIS determines both positive and negative impacts, and for the reliability criteria violations (i.e., the negative impacts) determines the alternate and preferred additional transmission facilities or other mitigation measures. Mitigation measures typically include: a) Special Protection System(s) which ramp down or drop a generating unit, b) predetermined operational measures establishing a generating unit's output, c) building new transmission facilities, d) putting higher capacity conductors on an existing transmission line, e) the use of intra zonal or inter zonal congestion management. The SIS is conducted with and without the new generation project and its interconnection facilities by using the computer model base case for the year the generator project would come on-line. The system configuration without the new generation project is referred to as the "pre-project" configuration and it establishes the baseline for identification of impacts caused by the new generation project. Establishment of the pre-project system configuration is necessary to meet FERC's requirements, and utility and CA ISO conforming tariffs to assure non-discriminatory access to the transmission grid. In the generator interconnection paradigm per the Federal Energy Regulatory Commission's (FERC) requirements, an Interconnection Application is filed, the applicant's facilities are described, the interconnection point is identified, a System Impact Study Agreement is signed and fees are paid. The CA ISO's tariff provides generally that an applicant secures a place in the queue for new generation projects when their application is received.

The SIS normally includes a Load Flow study, Transient Stability study, Post-transient Load Flow study and Short Circuit study. The study is focused on thermal overloads, voltage deviations, system stability (excessive oscillations in the generators and transmission system), voltage collapse, loss of loads or cascading outages and short circuit duties. The study must be conducted under normal conditions (N-0) of the system (see Definition of Terms) and also for all credible contingency/emergency conditions, which include the loss of a single system element (N-1) such as a transmission line, transformer or a generator and the simultaneous loss of two system elements (N-2), such as two transmission lines or a transmission line and a generator. The study may also be conducted for credible simultaneous loss of multiple (more than two) system elements. In addition to the above analysis, studies may be performed to verify whether sufficient active or reactive power margins are available in the system or sub-system to which the new generator project would be interconnected. Equipment that is loaded beyond 100 percent of its rating constitutes a violation of the reliability criteria. Generally, voltages must be within 95 percent and 105 percent of the base level.

The SIS is followed by supplemental studies conducted by the transmission owner with details provided in a Facility Study (FS) or a Facility Cost Report. The Facility Study determines engineering details and costs for mitigation measures required to assure that system reliability criteria violations are resolved and evaluates the costs ascribed to the generation developer for interconnection of the generating unit.

BART STUDY

Background

The CEC staff initiated a workshop to help the applicant prepare a computer model of a base case for the BEP II project on September 10, 2002 in Ontario, CA. The workshop was attended by the CEC staff, the applicant and their representatives, the representatives of affected transmission stakeholders (SCE, Western, MWD, IID, SDG&E (San Diego Gas & Electric) and others (Arizona Public Service (APS), and Salt River Project (SRP)). The purpose of the workshop was to build a consensus regarding system computer model base cases for 2006 summer peak electricity demand and 2006 light spring electricity demand conditions. Accordingly, a 2006 summer peak pre-project base case was developed by K. R. Saline and Associates, the applicant's consultant, from the WECC 06HS2SA base case published by WECC in June, 2002. Subsequently, a 2006 spring pre-project base case was developed by K. R. Saline and Associates from the 2006 summer peak pre-project base case by reducing loads and generation in the SCE system and loads in the IID system.

During the period between March, 2002 and August, 2003, the applicant submitted in total five different system studies, a SIS performed by SCE (BEP II, 2002c) and four BART studies (BART studies; BEP II, 2002h, 2003b, 2003c, 2003h, 2003f) performed by K. R. Saline and Associates for screening and feasibility of various alternative interconnections and new transmission options. The applicant finally selected the configuration dated August 14, 2003, considered as a feasibility study, for CEC certification with identified BEP II generator interconnection facilities and the proposed

DSWTP 500 kV line. The Study was performed under 2006 summer peak and 2006 spring conditions. In the summer peak base case, the interconnection facilities were not modeled according to the selected project configuration. Instead the Study modeled the project interconnection facilities and the new transmission line (BART SC4 base case) for the summer peak case as follows:

a. BEP II 500 kV and 230 kV Switchyards (BEP II units connected to BEP II 230 kV Switchyard bus) with a new short 230 kV interconnecting line between BEP II 230 kV switchyard and Buck Boulevard 230 kV Substation, and with two units of BEP I connected to Buck Boulevard Substation 230 kV Bus and one unit of BEP I connected to Buck Boulevard Substation 161 kV Bus.
b. A 500/230 kV transformer bank at the BEP II Switchyard.
c. A new 120-mile 500 kV line with 2-2156 ACSR conductor from the BEP II 500 kV Switchyard to SCE's Devers 500/230 kV Substation.

The study for spring case modeled the project interconnection facilities and the new transmission line (BART SC4 spring base case) as the selected project description above.

Scope of the BART Study

The August 14, 2003 BART study was considered by the applicant as a feasibility study in support of BEP II generator interconnection and provision for a new bulk 500 kV transmission line capacity to deliver power to the CA ISO grid at the Devers Substation (BEP II, 2003f).

The study modeled the proposed BEP II project for a net output of 520 MW and also modeled the BEP I 520 MW net power output (the BEP I plant is already on-line and interconnected to the Buck Boulevard Substation). The Power Flow studies were conducted by K. R. Saline and Associates with and without BEP II, with the interconnection facilities and the new DSWTP 500 kV transmission line for 2006 summer peak and 2006 spring system conditions. Analyses was done for normal (N-0), single (N-1) and credible double contingency (N-2) conditions. The spring study post-project base case was modeled according to the project configuration, but it was developed from the summer case by reducing loads and generation. The summer study post-project base case was not modeled according to the project configuration, but modeled with many approximations. While the applicant relies on the BART study, staff does not support its system assumptions or conclusions. The conclusions, which directly follow, apply to the study results submitted. Staff includes them here only as background.

Power Flow Study Results

Based on the August 14, 2003 BART study results, there are some adverse impacts following certain outages on the electrical grid due to interconnection of the BEP II as proposed. A summary of the overload violations under 2006 summer peak and spring conditions has been provided in Tables SC4.0, SC4.1, SC4.2, SC4.0 Spring, SC4.1 Spring and SC4.2 Spring of the study report (BEP II 2003f).

Mitigation of Overloaded Facilities and Comments

To offset the identified post-project overload violations due to interconnection of BEP II, the applicant selected mitigation measures without any written concurrence from the respective transmission owners and/or CA ISO. Staff requested the applicant (per CEC Data Request number 227e dated May, 2003), to provide a letter or a report from the respective transmission owner and, where applicable, from the CA ISO verifying the rationale and feasibility of the mitigation measure and its implementation for each criteria violation prior to the on-line date of the BEP II plant. No report or letters were received resulting in uncertainty about the feasibility of mitigation measures. Provision of such a letter or report is now moot as the overloaded facilities and mitigation measures will change when BEP II is analyzed in a new Blythe area transmission configuration.

Transient Stability Study

The applicant submitted a BART Stability Study report dated May 18, 2004 prepared by General Electric Energy. The study was conducted with a 2006 summer peak case and a 2006 spring case. The stability analysis shows that the system is both transiently and dynamically stable for all selected critical contingencies except for the loss of the Buck Boulevard-Devers 500 kV line. The analysis shows that this reliability criteria violation can be mitigated with the tripping of BEP II 520 MW power output (BEP II 2004a).

Short Circuit Study

The applicant submitted a BART Short Circuit Study report dated May 18, 2004 prepared by General Electric Energy. The study was conducted with a 2006 summer peak case with and without BEP II. The analysis shows that the addition of the DSWTP 500 kV line has the greatest impact on fault current increments in the Blythe area. However, the analysis was found incomplete as the breaker fault interrupting ratings at the selected substations were not provided by the applicant from the transmission owners (BEP II 2004a).

Comments on the BART Study

The applicant considered the August 14, 2003 BART study as a feasibility study and stated that it was not intended as a SIS. While staff concurred with the applicant that the purpose of the BART study was as a screening and feasibility study and not as a SIS, staff observes the BART study itself is incomplete and the study results are also preliminary due to system modeling issues and other reasons stated below.

The spring study post-project base case was modeled according to the project configuration as described above, but the summer study post-project 2006 base case (BART SC4 base case) was not modeled according to the project configuration, but instead with many physical, electrical approximations.

Staff modified the modeling of the summer BART SC4 CEC base case for 1) the 500/230/161 kV transformer at the Buck Boulevard Substation, 2) the new 500 kV line from the Buck Boulevard Substation to the Devers substation, and 3) the 500 kV short interconnection line from the BEP II Switchyard to the Buck Boulevard Substation. These changes were required so that the impedances (similar to the resistance) and configurations of the facilities would be accurately accounted for in the analytics of the computer analysis. After staff modified the modeling with the information available, staff's preliminary analysis found that the power flow to Devers from the Buck Boulevard Substation would be about 818 MW instead of 730 MW as shown in the BART SC4 CEC case.

Staff believes that discrepancies in modeling the new transmission elements for the interconnection of BEP II and their effects on the power flow results in a failure to identify realistic adverse impacts under normal and contingency conditions in the affected systems (SCE, IID, Western, San Diego Gas & Electric (SDG&E) and CFE (in Mexico)). Consequently, the study results would be affected and the selected mitigation measures could be wrong, ineffective or partially effective, and conformance with NERC/WECC, NERC, Western Interconnection and CA ISO planning standards and reliability criteria would not be assured.

In the development of the 2006 pre-project spring base case, staff found that the 2006 summer peak pre-project base case was converted to a spring case by reducing load and generation in the SCE system and by reducing loads in the IID system. Staff also observes that the BART study results dated August 14, 2003 show more adverse impacts under spring conditions than under summer peak conditions. Staff believes that a study developed from an original spring or autumn case published by the WECC would provide more reliable system impact results for power flow and for transient stability analyses.

To eliminate the identified post-project overload violations due to the addition of BEP II, the applicant selected mitigation measures without any written concurrence from the respective transmission owners and/or CA ISO. Staff requested the applicant (per CEC Data Request number 227e dated May, 2003), to provide a letter or a report from the respective transmission owner and, where applicable, from the CA ISO verifying the rationale and timely feasibility of the selected mitigation measures. Staff expected that in the SISs to be performed by SCE and Western, the mitigation measures would be selected by the applicant in concurrence with the respective transmission owner. No letters or reports have been received which results in uncertainty about the feasibility and validity of the outdated BART study.

The BART short circuit study report was also found incomplete as the breaker fault interrupting ratings were not provided by the applicant from the respective transmission owner(s). The BART study was also never formally approved by the stakeholders (SCE, Western and IID) and CA ISO.

Staff, therefore, finds that the BART study is inaccurate, incomplete and outdated, and does not meet the requirements of NERC/WECC and CA ISO reliability and planning standards.

CHANGED SYSTEM ASSUMPTIONS AND REQUIREMENTS FOR THE NEW SYSTEM IMPACT STUDIES

Because of the BEPTL modification plan, the transmission system in and around the Buck Boulevard Substation could undergo substantial changes. Since BEPTL is ahead of BEP II in the generation/transmission queue, Western and SCE have to provide a priority to the BEPTL in accordance with the applicable tariffs and are progressing first with the SISs for BEPTL. Subsequently, SCE will perform a BEPTL Facility Study, and finalize the BEP I sponsored transmission plan(s) for transmission lines emanating from the Buck Boulevard Substation. Because the BEP II applicant has signed Interconnection study agreements with SCE and Western, the new SISs for BEP II to be performed later by SCE and Western would include the BEPTL transmission plan(s) in the base case[4] and eventually have a different pre-project scenario of the transmission network in the Blythe area than that analyzed in the BART study (See **TSE Figures 1, 2, & 3**, attached). Staff anticipates the new SISs would have different system reliability impacts depending on their interconnection alternatives. Staff, therefore, concludes that the BART study is inaccurate and incomplete, and the BEPTL plan nullifies the BART study.

Moreover, staff became aware recently that in the SIS to be performed by SCE, the applicant is pursuing different interconnection and transmission alternatives than those proposed before the Commission, such as interconnecting to the existing DPV1 500 kV line or the SCE sponsored proposed DPV2 500 kV line. Additionally, the status of the DSWTP line is uncertain and publication of its final EIS/EIR report by the BLM and sponsors has been pending for an indefinite period (per BLM). Staff also became aware recently that the sponsors of the proposed DSWTP line are negotiating with SCE so that instead of building an independent DSWTP line (in the same BLM transmission corridor as the existing DPV1 and proposed DPV2 lines), the DSWTP potentially could become a part of the SCE sponsored DPV2 500 kV line between the Blythe area and Devers with a Midpoint Substation near Blythe.

In view of the uncertainty of the DSWTP line, the BEP II undefined interconnection and new transmission alternatives for the BEP II project, and the timing of the permits and the construction schedule, staff believes that instead of the applicant's originally anticipated summer 2006 on-line date, the earliest the BEP II plant could come on-line would be mid to late 2008 depending on the new transmission option(s) and assuming the Commission approves the project. The SISs for BEPTL are being performed for 2008 system conditions with and without the DPV2 line for summer peak and autumn system conditions (Blythe, 2004a & 2004b). The new SISs for the BEP II interconnection would likely be required to be performed by SCE and Western on the same basis for 2008 or 2009 summer peak and autumn off-peak conditions as stated in the Conclusions and Recommendations. Staff is and will participate with the applicant, SCE, the CA ISO and Western (and other stakeholders) in the development of required System Impact Studies and Facility Studies.

[4] The base case for a SIS models the California and other western state's entire transmission and generation system. The pre-project base case includes all transmission and generation facilities anticipated to exist just before the studied generating unit or transmission facility would come on line.

A NEW SIS FOR INTERCONNECTION OF THE BEP II PLANT TO THE WESTERN'S BUCK BOULEVARD SUBSTATION WITH THE DSWTP TRANSMISSION OPTION HAVE RECENTLY BEEN INITIATED BY WESTERN ON BEHALF OF THE BEP II APPLICANT. THE STUDY INCLUDES THE BEPTL TRANSMISSION PLAN AND DPV2 LINE AS A PRE-PROJECT SYSTEM CONFIGURATION (WESTERN, 2005). THIS IS A NOTABLE RECENT DEVELOPMENT AND CONFORMS TO STAFF'S CONCLUSIONS AND REQUESTS FOR NEW SISS BE PERFORMED BY WESTERN AS WELL AS SCE AS STATED ABOVE. THE APPLICANT ALSO HAS NOT DIRECTLY PROVIDED ANY INFORMATION ABOUT ITS RECENT ALTERNATIVE INTERCONNECTION AND TRANSMISSION OPTIONS TO THE CA ISO GRID IN RESPONSE TO STAFF'S REQUESTS.CA ISO REVIEW AND APPROVAL

Unlike other applications for certification where generating units connect directly to the CA ISO grid, since the Western system (Buck Boulevard Substation) is not a part of the CA ISO grid, the CA ISO is not responsible for ensuring electric system reliability for the generator interconnection to the Western System. However, the CA ISO is responsible for ensuring that delivery of BEP II generation to the CA ISO grid (SCE's Devers Substation or any other) through the proposed DSWTP 500 kV line from Western's Buck Boulevard Substation does not cause any potential reliability concerns. Should the BEP II project move forward with interconnection to the DPV1 or DPV2 line, the CA ISO will be responsible for evaluating system reliability impacts, and providing review and approval for interconnection of the project to the CA ISO grid. A SIS and a Facility study, with the queue generation and transmission projects properly modeled, are required for the CA ISO review and approval for interconnection of the DSWTP line or any other line to the CA ISO grid. Staff is uncertain when the new SIS reports will be available to the CA ISO and staff.

STATUS OF THE DSWTP 500 KV TRANSMISSION LINE

The BART feasibility and screening study first concludes that the project would require construction of the BEP II integration switchyard and 500 kV interconnection transmission facilities to Western's Buck Boulevard Substation as proposed by the applicant. However, the BART study also states that accommodating the power output of BEP II will require a new bulk power transmission line from Buck Boulevard Substation or the BEP II plant to Devers or other load centers in the CA ISO grid. This is due to limited transmission capacity availability in the "south of Parker" Western system, especially given interconnection of the existing BEP I plant to the Buck Boulevard Substation. In response to this conclusion, the applicant stated that it would utilize the proposed DSWTP line (See **TSE Figure 3**, attached).

Despite the other transmission options available (described above), this is the only configuration staff is assessing since it is the configuration the applicant has requested the Commission to license. Staff believes that the proposed DSWTP 500 kV line would provide the most comprehensive and expedited solution to delivering 1040 MW power output from both the BEP I and BEP II plants to the CA ISO grid. However, staff has insufficient information from the applicant or sponsors about the status of building the DSWTP line and its expected completion date. No information has been received by the staff directly from SCE or Western about the specific engineering details of the new facilities and/or modifications involved in the SCE and Western substations to accommodate the DSWTP at its terminations.

Since 2003 IID, DSP and the Bureau of Land Management (BLM) have been jointly pursuing an EIS/EIR with various options and routes for a proposed DSWTP (BEP II, 2003g. Draft Environmental Impact statement/Environmental Impact Report (EIS/EIR), 03-25-03). According to the EIS/EIR the line would start from a new IID Hobsonway 230 or 500 kV Substation near the BEP II project and terminate at SCE's Devers 500/230 kV Substation and it could loop into IID's Coachella or Dillon Road 230 or 500 kV Substation before terminating at the Devers 500/230 kV Substation. This engineering description is not consistent with the system configuration as shown in the BART study where the DSWTP line starts from the Buck Boulevard Substation.

According to recent information from BLM, staff's understanding is that publication of the final EIS/EIR report by BLM and sponsors is deferred for an indefinite period. Moreover, staff became aware that the sponsors of the DSWTP line are negotiating with SCE so that instead of building a separate DSWTP line (in the same planned BLM transmission corridor beside the existing DPV1 and proposed DPV2 lines), it may become a part of the SCE sponsored proposed Devers-Palo Verde No. 2 500 kV line (DPV2) between Blythe and Devers with a Midpoint Substation at Blythe. Therefore, the feasibility of building the new DSWTP line itself in a timely manner before the projected on-line date of BEP II remains still uncertain at this stage and the target date for completion of DPV2 line by SCE is now 2009, which staff believes is also uncertain. Consequently the feasibility of the BEP II project also remains uncertain.

CUMULATIVE SYSTEM RELIABILITY IMPACTS

Cumulative system reliability impacts can occur when a new generating unit or new transmission facility is connected to the grid and the increased or modified power flow of the new generating unit or new transmission facility affects a generating unit's or transmission line's later interconnection.

Cumulative system reliability impacts are evaluated based on the applicable generation/transmission queue. Each project requesting interconnection to the grid is evaluated based on existing conditions anticipated for its online date.

Staff believes the queue applicable to BEP II, as determined by the applicable interconnection tariffs, is 1) DPV2, 2) BEPTL and 3) BEP II and the DSWTP[5]. Staff has no studies with BEP II and the DSWTP (or alternative undefined interconnections) connected per their queue position (number 3), thus staff cannot identify even the "direct" impacts of the BEP II project. The direct impacts of BEP II must be established with and without the DPV2 line and with the BEPTL lines as the pre-project configuration (e.g., the existing system in mid to late 2008 and then BEP II modeled on-line in the same study year; thereby identifying the direct impacts caused by the BEP II project and any interconnection facilities). Once direct system reliability impacts are established, then approximate cumulative system reliability impacts can be estimated.

[5] Staff established this conclusion based on the BEPTL SISs which do not include BEP II as an assumption in the studies and assesses the DPV2 line as operational and not operational.

In some instances cumulative environmental impacts can result from cumulative system reliability impacts. As an example, the stress caused by a generating unit ahead in the queue when combined with the stress caused by a lower unit may require construction of a new transmission line or reconductoring of an existing line.

Because the direct impacts of interconnecting BEP II in an unidentified manner cannot be determined, staff cannot identify what cumulative system reliability or environmental impacts would occur should a later generation unit or other transmission facility be proposed in the area.

COMPLIANCE WITH LORS

Staff concludes that the BART study submitted does not comply with NERC/WECC, NERC and CA ISO planning standards for the interconnection of a generating unit due to the various reasons stated above. Therefore, the project and its interconnection cannot be evaluated for conformance with system reliability LORS. Additionally, no firm information describing interconnection of BEP II to the Buck Boulevard Substation (or elsewhere) is available given that the BEPTL project facilities would be installed prior to any BEP II facility interconnection to the grid. Therefore, conformance with engineering LORS such as General Order 95, the National Electric Safety Code, IEEE grounding standards and Western and SCE interconnection standards cannot be evaluated. Staff, therefore, concludes that the identified interconnection facilities cannot be analyzed for conformance with engineering or system reliability LORS at this stage. Should the Commission approve the BEP II project, notwithstanding staff's concerns the Conditions of Certification TSE-1 through TSE-9 should be required.

FACILITY CLOSURE

Planned Closure

This type of closure occurs in a planned and orderly manner such as at the end of the generation facility's useful economic or mechanical life or due to gradual obsolescence. Under such circumstances, the owner is required to provide a closure plan 12 months prior to closure, which in conjunction with applicable LORS is considered sufficient to adequately provide for safety and reliability. For instance, a planned closure provides time for the owner to coordinate with the Transmission Owner (TO), in this case Western, to assure (as one example) that the TO's system will not be closed into the outlet thus energizing the project substation. Alternatively, the owner may coordinate with the TO to maintain some power service via the outlet line to supply critical station service equipment or other loads.[6]

Unexpected Temporary Closure

An unplanned closure occurs when the facility is closed suddenly and/or unexpectedly for a short term due to unforeseen circumstances such as a natural or other disaster or emergency. During such a closure the facility cannot insert power into the utility system. Closures of this sort can be accommodated by establishing an on-site

[6] These are mere examples, many more exist.

contingency plan (see **General Conditions Including Compliance Monitoring and Closure Plan**).

Unexpected Permanent Closure

This unplanned closure occurs when the project owner vacates the facility. This is considered to be a permanent closure. This includes unexpected closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unexpected closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned. An on-site contingency plan, that is in place and approved by the Energy Commission's Compliance Project Manager (CPM) prior to the beginning of commercial operation of the facilities, will be developed to assure safety and reliability (see **General Conditions Including Compliance Monitoring and Closure Plan**).

RESPONSE TO PUBLIC AND AGENCY COMMENTS

No agency or public comments applicable to the TSE discipline have been received.

RESPONSE TO APPLICANT COMMENTS

In April of 2004 staff received the Applicant's comments on Transmission System Engineering. In the comments, the Applicant recommends words for a condition of certification that would ostensibly allow the project to go forward without information on the interconnection configuration. As discussed previously staff does not believe such a condition is appropriate given the lack of information needed to analyze transmission system impacts. Staff nonetheless has proposed conditions of certification in the event the Commission approves the project.

The applicant suggested the following language:

> **Condition TSE No. _____:** The Project Owner shall not commence construction until the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) has received all necessary permits. The Project Owner shall not deliver to the grid more than ____ megawatts combined from the Blythe I and Blythe II projects until the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) has been constructed and is in operation.
>
> **Verification:** Not later than 30 days prior to commencement of construction, the Project Owner shall provide to the CPM a statement from the owner(s) of the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) that all necessary permits have been issued. Not later than 30 days prior to delivery to the grid from the Blythe I and Blythe II projects of greater than ____ megawatts, the Project Owner shall submit to the CPM a statement from the owner(s) of the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) that the project is operational.

Staff advised the applicant at the January 26, 2005 PSA workshop that we would not support the suggested condition because it could not suffice adequately for identification of the applicant's project facilities and alternatives, assessment of impacts and mitigation measures, conformance with LORS and the Commission's responsibility to assure conformance with CEQA. Staff has numerous problems with the specific provision of the suggested condition as stated:

- The condition provides for an unprecedented situation where an applicant could propose an "essential" project facility, the Commission approve it and then an unknown facility with unknown impacts (both reliability, engineering LORS, and environmental) be substituted after project approval. The remedy for securing adequate capacity to deliver power to the grid is to request interconnection, secure SISs and approval to interconnect. Depending on an unknown facility is a clear violation of the Commission's responsibility to analyze impacts pursuant to CEQA before a project is approved. The Commission must identify and analyze the "whole of the action" before approving a proposed project. A critical piece of BEP II is inadequately described and, therefore, cannot currently be analyzed.

  Nor does the condition acknowledge that the applicant is currently pursuing other interconnection configurations. Were BEP II approved with the proposed condition the project owner would be prohibited from seeking a modification to the interconnection configuration. Title 20, California Code of Regulations, Section 1769 allows a modification to a permit only if the Commission finds either that there has been a substantial change in circumstances since the project was certified or the change is based on information not known prior to certification. Clearly, the applicant could meet neither test.

- The condition also restricts the combined output of both BEP I and BEP II pending some unknown transmission facility being constructed and operating in the future. Also, the condition could be taken as limiting output of a generating unit (BEP I) already licensed by the Commission that has sufficient outlet capacity so that BEP II could operate. Staff concludes that it would be impossible to fashion a contractual provision under the Commission's authority to control two (or even one) generating unit's output; this is FERC's purview and that of the CA ISO and Western in their conforming tariffs.

- The verification provides 30 days for the CPM to decide if necessary permits for the DSWTP or some other unknown transmission outlet are sufficient to reliably and fully accommodate an output of 1040 MW (BEP I and BEP II). Because the purpose of the ill-founded Condition is to secure adequate outlet capacity, the existence of mere permits in a verification would not suffice. The Applicant would have to provide a SIS and FS and path rating studies for either the DSWTP or an alternative outlet. Additionally, approval by Western and the CA ISO (where applicable) would be required because there are instances where permits from a siting and environmental perspective may exist but system reliability analysis and outlet capability not exist (Note worthy at present is the DSWTP which does not have the required SIS, FS and path rating studies to allow interconnection or operation—but has a DEIS/DEIR.) Assuming a SIS, FS, path rating studies and approval by the CA ISO or Western (where applicable) were provided staff estimates we would need approximately three months to recommend approval before the full Commission assuming adequate environmental review by an authorized agency. That also assumes that if an alternative outlet is proposed the Commission does not have licensing jurisdiction. Several transmission alternatives previously proposed by the Applicant fall under the Commission's licensing authority. Additionally, an alternative presently requested by the Applicant for termination on DPV1 is under the Commission's licensing authority. Should that occur staff estimates about 6 months for approval.

APPLICANT'S APRIL 2004 COMMENTS

The applicant also provided comments in April 2004 on information that they agreed to provide as follows (only the major heading and staff's response are presented here):

Stability and Short Circuit Studies

The applicant states that the studies were completed. Staff concludes they were not completed, as breaker ratings must be identified to determine if breakers must be replaced but this was not done. This issue is moot as the pre project configuration, due to the BEPTL, has changed and this will change the results of the analysis.

Plan View of Buck Boulevard Substation:

A conceptual plan was presented. This plan however lacks engineering details and is obsolete given the pre project configuration caused by the BEPTL. It is infeasible from an engineering perspective to connect the BEP II project as depicted and also simultaneously connect the BEPTL project as they propose. The BEP II project configuration combines most of both the BEP I and BEP II output power on the Buck Boulevard bus and transmits almost all of the power to the Devers Substation via the DSWTP. The BEPTL project configuration places only BEP I power on the Buck Boulevard bus and transmits that power to the Julian Hinds Substation or DPV1 via one or two 230 kV lines. The BEPTL project configuration does not model the BEP II project or the DSWTP connected to the grid at all. Staff is not suggesting that some manner of connecting BEP I and BEP II and the DSWTP plus the two 230 kV lines (or some combinations with fewer lines) cannot be developed but rather that there is no defined proposal available at this time. Because there is no proposal, the design of the Buck Boulevard Substation is unknown and conformance with engineering LORS cannot be determined. Likewise, because the configuration of lines emanating from Buck Boulevard is unknown the spatial delivery of power to the grid is unknown, thus system reliability criteria violations and mitigation measures are unknown. The BEPTL is ahead of the BEP II project in the queue and they have first rights to interconnection.

Plan View of the Integration Switchyard:

While a plan view of the originally proposed Integration Switchyard was provided it is not up to date given that the proposed BEPTL project is now ahead in the queue.

Verification of Mitigation Measures for Criteria Violations per BART Executive Summary:

Staff never received written verification from the transmission owners and CA ISO agreeing that the BART study was sufficient to identify any network upgrades with possible environmental impacts. Such verification is now moot, as staff knows that SCE, Western and the CA ISO cannot provide conclusions based on an outdated study where significant system changes are known to be occurring. The CA ISO has indicated that they are unable to provide comments to the Commission based on the BART study which is known to be outdated, nor can they provide a preliminary approval of interconnection of the DSWTP or testimony before the Commission.

Devers Import Nomogram:

The applicant believes an existing CA ISO approved nomogram can be used for the BEP II generation impacts. Staff disagrees; the feasibility of using an existing nomogram for interconnection of BEP II and the DSWTP can only be determined by appropriate studies conducted per the queue, and provision of a SIS and FS approved by the CA ISO and subject to interconnection approval by Western. The CA ISO, SCE and Western are bound by their tariffs to provide non-discriminatory access to the grid and as such, approvals are provided in accordance with the queue.

Staff makes the following comments on the applicant's memorandum regarding "BART Consensus on Mitigation for Critical Contingencies for BEP II:"

- The memorandum notes that prior to interconnection of the BEP II facility "additional power flow work, transient stability and short circuit studies were to be performed as part of [the] final system impact studies by each of [the] BART Participants (sic) pursuant to their individual OATT[7] Processes (sic)."

  Staff anticipated that while the joint studies would not suffice for the OATT processes and approvals provided per that process the joint studies would provide staff with a sufficient confidence level regarding the system reliability criteria violations and the mitigation measures required by each stakeholder (Western, SCE, MWD, CA ISO, APS, SDG&E or others) that we could identify the "whole of the action" per CEQA; this did not occur. The interconnection studies morphed into feasibility studies for many alternative interconnections to the grid and the stakeholders indicated that they could not use the BART study to indicate system reliability criteria violations and mitigation measures. Upon learning of these developments staff informed the Applicant that SISs performed per the queue would have to be provided. The applicant refused.

- The memorandum also states: "For the purposes of the CEC review for the Final Staff Assessment ("FSA") that is expected to be completed the end of April 2004, the above conclusions support that no new additional transmission facilities or upgrades that have not already been identified will be required outside the SCE, Western, and IID substation fences (just inside the fences such as breakers, switches, etc.)". This assertion implies that the conclusions flowing from the BART study were sufficient to identify the system reliability criteria violations and the acceptability of those mitigation measures by the affected transmission owners and the CA ISO. Staff disagrees with that assertion as previously discussed. The assertion also suggests that the staff would find that the conclusions flowing from the BART study were sufficient. Staff does not agree with this conclusion as previously stated.

[7] OATT is an acronym for Open Access Transmission Tariff. Staff has previously referred to the Open Access Transmission Tariff simply as the applicable tariff or the conforming tariff.

The deficiencies noted by staff on the BART study are historically substantial but presently irrelevant and immaterial to what will actually become an interconnection of the BEP II project --should the Commission approve it and the applicant build it. The applicant either did not file timely for a position in the generation/transmission queue or they fell out of it and therefore the applicant's "project" is undefined. The FERC, CA ISO, SCE and Western tariffs require BEP II to be studied per the queue. It has not been, and because the proposed BEPTL project facilities must be assumed to exist prior to connecting BEP II or the DSWTP, completely different impacts will occur. Staff anticipates that the BEP II project configuration will ultimately be significantly different than what the applicant has suggested based on the outdated BART study.

CONCLUSIONS AND RECOMMENDATIONS

The existing information on system reliability impacts and the design of the Buck Boulevard Substation is incomplete. Staff offers the following comments:

1) The BART study dated August 14, 2003, considered as a screening and feasibility study, is incomplete and the study results are preliminary. As stated in Staff's preliminary assessment (PSA), due to modeling discrepancies and approximations of the BEP II project interconnection facilities and the proposed DSWTP transmission line, and without a proper spring base case, staff does not believe that the Power Flow study results have identified all system reliability criteria violations and their degree of impacts in the affected systems of SCE, IID, SDG&E and Western. Also, the Short Circuit study report dated May 18, 2004 as submitted is incomplete as breaker fault interrupting ratings were not provided. Moreover, the mitigation measures selected by the applicant to eliminate identified overload violations in the Power Flow study were not verified with written consensus from the stakeholders (SCE, Western, IID) and CA ISO about the feasibility and rationale of the mitigation measures. The BART study was never formally approved by the stakeholders and CA ISO. Staff therefore concludes that the BART study submitted does not comply with NERC/WECC and CA ISO planning and reliability standards. Staff also believes the requirements of CEQA for identifying the "whole of action" would not be met if the project is approved without necessary studies.

2) The diagrams submitted for the project by the applicant for the proposed BEP II integration switchyard, interconnection facilities and Buck Boulevard 500 kV Substation are conceptual and indeterminate. The diagrams do not provide specific details of the proposed new and modified installations with major equipment ratings including facilities for termination of the new proposed DSWTP 500 kV line at both ends. Without an adequate description of these facilities the project description is inadequate and the staff is unable meet the CEQA requirement to analyze the "whole of the action."

3) The BART study concludes that BEP II can be interconnected to the electrical grid at the Western Buck Boulevard Substation, but delivering the power output of the BEP II and/or BEPI, will require a new bulk power transmission line from the Buck Boulevard Substation or the BEP II Switchyard to Devers or other load centers due to limited transmission capacity availability in the "South of Parker" Western

system. In this respect, the DSWTP 500 kV line was identified by the applicant and the BART study was performed with the DSWTP line. Staff believes that the proposed DSWTP 500 kV line would provide the most comprehensive and expedited solution to delivering power output from both the BEP I and BEP II plants to the CA ISO grid. However, the status of the DSWTP line is uncertain, since publication of its final EIS/EIR report by the BLM and sponsors has been deferred for an indefinite period for unknown reasons. Staff also became aware recently that the sponsors of the proposed DSWTP line are negotiating with SCE so that instead of building an independent DSWTP line in the planned BLM transmission corridor beside the existing DPV1 and proposed DPV2 lines, the DSWTP could become a part of the SCE sponsored DPV2 500 kV line between Blythe and Devers with a Midpoint Substation near Blythe. Therefore, building the new DSWTP line in a timely manner before the on-line date of BEP II (estimated by staff for mid to late 2008) is uncertain. The target date for completion of the DPV2 line by SCE is now 2009, which staff believes is also uncertain. Consequently, the feasibility of the BEP II project also remains uncertain.

4) Staff became aware recently that the applicant has signed interconnection study agreements with SCE and is pursuing a different interconnection alternative than proposed before the Commission such as interconnecting to the existing DPV1 500 kV line or to the proposed DPV2 500 kV line. No engineering descriptions or system reliability studies are available for these terminations. The SISs to be performed by SCE for these terminations have not started yet.

5) Because of the BEP I sponsored proposed transmission line modifications for delivering 520 MW of BEP I project power from the Buck Boulevard Substation to the CA ISO grid, the transmission system in and around the Buck Boulevard Substation will undergo substantial additions and changes if the modifications are approved. Since the BEPTL is ahead of the BEP II project in the generation/transmission queue, Western and SCE have to provide a priority to BEPTL and are, therefore, progressing first with the SISs for the BEPTL plan. SCE must first perform the BEPTL Facility Study and finalize the BEPTL plan in the Buck Boulevard Substation before a configuration for BEP II can be determined. Since the applicant has signed Interconnection study agreements with SCE and Western, the new SISs for BEP II to be performed later by SCE and Western would include the BEPTL transmission plan in the base case and have a different pre-project scenario for the transmission network in the Blythe area than that assumed in the BART study. Staff anticipates the new SISs would have different system reliability impacts depending on BEP II's interconnection alternatives. Staff concludes that the BEPTL plan nullifies the BART study and therefore, the project related facilities in the Buck Boulevard Substation, the outlet lines for power delivery and the system reliability criteria violations and mitigation measures caused by interconnection of BEP II to the grid are unidentifiable at this time.

6) In view of the uncertainty of the DSWTP line and interconnection alternatives for the BEP II project, new system reliability studies, permits and construction schedule, staff believes that the earliest the plant could come on-line would be mid to late 2008. Also, since the BEPTL studies are being performed based on year 2008 system conditions with and without the DPV2 line, the new SISs would likely

be performed by SCE and Western on the same basis for the 2008/2009 summer peak and autumn off-peak conditions.

7) Because the Western system is not a part of the CA ISO grid, the CA ISO is not responsible for the generator interconnection to the Western System. However, the CA ISO is responsible for ensuring that there are no reliability impacts on the CA ISO grid due to a generator interconnection on the Western system particularly when the interconnection point is electrically tied to the CA ISO-controlled grid. The CA ISO is also responsible for evaluating delivery of the BEP II generation to the CA ISO grid (SCE's Devers Substation or any other) through the proposed DSWTP 500 kV line from Western's Buck Boulevard Substation. Should the BEP II be planned to be interconnected to the DPV1 or DPV2 line, the CA ISO will be directly responsible for ensuring system reliability impacts and reviewing and providing an approval for interconnection of the project. A SIS/Facility Study, with the queue projects properly modeled, are required for the CA ISO review and approval for interconnection of the project.

8) Staff cannot identify either the direct system reliability impacts or the cumulative system reliability impacts.

9) Because staff's standard conditions are not sufficient to remedy the preliminary nature of the BART studies that are now nullified due to the proposed BEPTL plan and because staff cannot confidently identify the project facilities, non-standard conditions of certification have been proposed. A condition of certification that attempts to assure that the BEP II project not commence construction until the DSWTP line or some other unidentified line receives necessary permits in these circumstances as has been proposed by the applicant cannot remedy a nonconformance with LORS and CEQA as far as the project itself and its impacts are concerned.

10) Staff cannot recommend that the Commission approve the BEP II project until critical information is provided because the project is undefined. The impacts of the project and required mitigation measures are indeterminate and the Commission's responsibility to identify the "whole of the action" and to analyze the project impacts pursuant to CEQA before a project is approved cannot occur with available information.

1) Staff's recommendation was contained in the 'Motion To Compel Applicant To Submit Certain Information On Proposed Transmission Interconnection Configurartion', May 9, 2005, which was subsequently denied by the Committee. While staff retains the position that the identified information should be provided prior to certification, in light of the Committee's decision on this topic, staff is recommending the following Conditions of Certification TSE-1 through TSE-9 in the event the Commission approves the project.

TRANSMISSION SYSTEM ENGINEERING CONDITIONS OF CERTIFICATION

TSE-1 The project owner shall furnish to the CPM and to the CBO a schedule of transmission facility design submittals, a Master Drawing List, a Master Specifications List, and a Major Equipment and Structure List. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide designated packages to the CPM when requested.

Verification: At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction of any transmission facility, the project owner shall submit the schedule, a Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in **Table 1: Major Equipment List** below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Equipment List
Breakers
Step-up Transformer
Switchyard
Busses
Surge Arrestors
Disconnects
Take off facilities
Electrical Control Building
Switchyard Control Building
Transmission Pole/Tower
Grounding System

TSE-2 Prior to the start of construction of any transmission facility, the project owner shall assign an electrical engineer and at least one of each of the following to the project: A) a civil engineer; B) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; C) a design engineer, who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; or D) a mechanical engineer. (Business and Professions Code Sections 6704 et seq., require state registration to practice as a civil engineer or structural engineer in California.)

The tasks performed by the civil, mechanical, electrical or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer. The civil, geotechnical or civil and design engineer assigned in conformance with Facility Design condition **GEN-5**, may be responsible for design and review of the TSE facilities.

The project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all engineers assigned to the project. If any one of the designated engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer. This engineer shall be authorized to halt earthwork and to require changes; if site conditions are unsafe or do not conform with predicted conditions used as a basis for design of earthwork or foundations.

The electrical engineer shall:

1. Be responsible for the electrical design of the power plant switchyard, outlet and termination facilities; and
2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

TSE-3 If any discrepancy in design and/or construction is discovered in any transmission facility engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend corrective action. (1998 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval and shall reference this condition of certification.

Verification: The project owner shall submit a copy of the CBO's approval or disapproval of any corrective action taken to resolve a discrepancy to the CPM within 15 days of receipt. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action required to obtain the CBO's approval.

TSE-4 For the power plant Integration Switchyard, outlet line and termination, the project owner shall not begin any increment of construction until plans for that increment have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. The following activities shall be reported in the Monthly Compliance Report:

a) receipt or delay of major electrical equipment;
b) testing or energization of major electrical equipment; and
c) the number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant switchyard, outlet line and termination, including a copy of the signed and stamped statement from the responsible electrical engineer attesting to compliance with the applicable LORS, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report. [3/12/03]

TSE-5 The project owner shall ensure that the design, construction and operation of the proposed power plant integration switchyard, transmission line and Buck Blvd. Substation will conform to all applicable LORS, including the requirements and description listed below. No increment of construction shall commence until the CPM approves the documents required in the Verification for TSE-5. The project owner shall submit the required number of copies of the design drawings and calculations as determined by the CBO.

The BEP II 500 kV integration switchyard shall have four switchbays with 500 kV circuit breakers. The high voltage transformer terminals of two CTGs and one STG unit shall be connected by overhead conductors to three switch bays. The fourth bay shall be connected to a 500 kV 2-2156 Aluminum Conductor Steel Reinforced (ACSR) interconnecting line to a new 500 kV substation to be built as an expansion of the existing Buck Boulevard Substation.

The integration switchyard shall be connected to the Buck Blvd. 500 kV Substation via a 500 kV single circuit lattice tower line.

The expansion of the Buck Blvd. 500 kV substation shall include three switch bays with 500 kV circuit breakers. The 500 kV facilities shall be connected to the existing Buck Blvd. 161/230 kV Substation by installing a 400 MVA 500/230/161 kV step-down dual voltage transformer to transfer power to the DSWTP Line which shall be connected to the third 500 kV switch bay.

a) The power plant Integration Switchyard and outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the “High Voltage Electric Safety Orders”, Western Interconnection standards, IEEE grounding standards, National Electric Code (NEC) and related industry standards.

b) Breakers and busses in the power plan switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

c) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner’s standards.

d) The project conductors shall be sized to accommodate the full output from the project.

e) Termination facilities shall comply with applicable Western interconnection standards.

f) The project owner shall provide to the CPM:

- i) A System Impact Study and a final Detailed Facility Study (DFS) conducted by Western which includes,
  - (1) a description of all interconnection facilities with a one-line diagram including BEP II integration switchyard and the new Buck Boulevard 500 kV substation showing major equipment and their ratings.
  - (2) a description, including a one-line diagram, of all modifications to the existing Buck Boulevard Substation
  - (3) descriptions of any mitigation measures selected by project owner (to offset reliability criteria violations) and letters or reports of acceptance from the affected transmission owners and where applicable, the CA ISO.
- ii) A System Impact Study and a final Detailed Facility Study conducted by SCE and coordinated with the CA ISO for termination of the 500 kV DSWTP at Devers including:
  - (1) a description of all modifications in the Dever’s Substation,
  - (2) new downstream linear facilities or linear facility upgrades,
  - (3) descriptions of any mitigation measures selected by project owner (to offset reliability criteria violations) and letters or reports of acceptance from the affected transmission owners and where applicable, the CA ISO.
- iii) A final Interconnection Approval by the CA ISO for termination of the DSWTP at Devers.
- iv) Executed DSWTP project owner and CA ISO Interconnection Agreement.
- v) Executed project owner and Western BEP II Facility Interconnection Agreement.
- vi) Executed DSWTP project owner and Western Interconnection Agreement.

vii) Should new downstream linear facilities or downstream linear facility modifications be required due to interconnection and/or operation of BEP II or the DSWTP, the project owner shall provide an environmental assessment conducted at a level of analysis approved by the CPM.

Verification: At least 90 days prior to the start of construction of transmission facilities (or a lessor number of days mutually agreed to by the project owner and CBO, the project owner shall submit to the CBO and where applicable the CPM for approval:

a) Design drawings, specifications and calculations conforming with CPUC General Order 95 or NESC, Title 8, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", NEC, applicable interconnection standards and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment.

b) For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on "worst case conditions"[8] and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", IEEE grounding standards, NEC, applicable interconnection standards, and related industry standards.

c) Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements **TSE-5** a) through f) above.

d) Item f) above submitted to the CPM for approval.

TSE-6 The project owner shall inform the CPM and CBO of any impending changes, which may not conform to the requirements **TSE-5** a) through f), and have not received CPM and CBO approval, and request approval to implement such changes. A detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change shall accompany the request. Construction involving changed equipment or substation configurations shall not begin without prior written approval of the changes by the CBO and the CPM.

Verification: At least 60 days prior to the construction of transmission facilities, the project owner shall inform the CBO and the CPM of any impending changes which may not conform to requirements of **TSE-5** and request approval to implement such changes.

[8] Worst case conditions for the foundations would include for instance, a dead-end or angle pole.

TSE-7 The project owner shall provide the following Notice to the Western Area Power Administration, Desert Southwest Region (Western, DSR) and the California Independent System Operator (Cal-ISO) prior to synchronizing the facility with the California Transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the Western, DSR and Cal-ISO a letter stating the proposed date of synchronization; and
2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the Western, DSR and Cal-ISO Outage Coordination Department.

Verification: The project owner shall provide copies of the Western, DSR and Cal-ISO letters to the CPM when they are sent to the Western, DSRand Cal-ISO one week prior to initial synchronization with the grid. The project owner shall contact the Western,DSR and Cal-ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the Western, DSR and Cal-ISO shall be provided electronically to the CPM one day before synchronizing the facility with the Western, DSR California transmission system for the first time.

TSE-8 The project owner shall be responsible for the inspection of the transmission facilities during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", applicable interconnection standards, IEEE grounding standards, NEC and related industry standards. In case of non-conformance, the project owner shall inform the CPM and CBO in writing, within 10 days of discovering such non-conformance and describe the corrective action(s) to be taken.

Verification: Within 60 days after first synchronization of the project, the project owner shall transmit to the CPM and CBO:

"As built" engineering description(s) and one-line drawings of the Integration Switchyard, 500 kV line to the Buck Blvd.Substation , and termination facilities including all new and modified facilities inside Buck Blvd. Substation signed and sealed by the registered electrical engineer in responsible charge. A statement attesting to conformance with CPUC GO-95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders IEEE grounding standards, and applicable interconnection standards, NEC, related industry standards, and these conditions shall be provided concurrently.

a) An "as built" engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. "As built" drawings of the electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the "Compliance Monitoring Plan".

b) A summary of inspections of the completed transmission facilities, and identification of any nonconforming work and corrective actions taken, signed and sealed by the registered engineer in charge.

REFERENCES

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BEP II (Blythe Energy Project Phase II). 2002a. Submittal of the Application for Certification (AFC), Vol 1 & 2. 02/20/2002 (tn: 24604)

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Blythe Energy, LLC, Blythe, California (BLYTHE) 2004b. Additional Information-Petition for Modification. Submitted to the Docket on October 15, 2004.

CEC (California Energy Commission). 2002a. Data Requests. 08/23/2002 (tn: 26519)

CEC (California Energy Commission). 2002b. Second Round Data Requests. 12/30/2002 (tn:27752)

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DSP (Desert Southwest Power, LLC). 2005. Comments of Desert Southwest Power on Blythe I Transmission Line Amendment, March 2005.

NERC (North American Electric Reliability Council) 1998. NERC Planning Standards, September 1997.

WECC (Western Electricity Coordinating Council) 2001. NERC/WECC Planning Standards, June 2001.

Western (Western Area Power Administration) 2005. Email from Nick Saber on BEP II system integration, April 2005.

TSE ATTACHMENT 1: LORS

- NERC Planning Standards provide national policies, standards, principles and guidelines to assure the adequacy and security of the electric transmission system. The NERC planning standards provide for system performance levels under normal and contingency conditions. With regard to power flow and stability simulations, while these Planning Standards are similar to NERC/WECC Standards, certain aspects of the WECC standards are either more stringent or more specific than the NERC standards for Transmission System Contingency Performance. The NERC planning standards apply to interconnected systems and to individual service areas (NERC 1998).
- The National Electric Safety Code, 1999 provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation.
- The Western Electricity Coordinating Council (WECC) Planning Standards are merged with the North American Electric Reliability Council (NERC) Planning Standards and provide the system performance standards used in assessing the reliability of the interconnected system. Certain aspects of the NERC/WECC standards are either more stringent or more specific than the NERC standards alone. These standards provide planning for electric systems so as to withstand the more probable forced and maintenance outage system contingencies at projected customer demand and anticipated electricity transfer levels, while continuing to operate reliably within equipment and electric system thermal, voltage and stability limits. These standards include the reliability criteria for system adequacy and security, system modeling data requirements, system protection and control, and system restoration. Analysis of the WECC system is based to a large degree on Section I.A of the standards, "NERC and WECC Planning Standards with Table I and WECC Disturbance-Performance Table" and on Section I.D, "NERC and WECC Standards for Voltage support and Reactive Power". These standards require that the results of power flow and stability simulations verify defined performance levels. Performance levels are defined by specifying the allowable variations in thermal loading, voltage and frequency, and loss of load that may occur on systems during various disturbances. Performance levels range from no significant adverse effects inside and outside a system area during a minor disturbance (loss of load or a single transmission element out of service) to a level that seeks to prevent system cascading and the subsequent blackout of islanded areas during a major disturbance (such as loss of multiple 500 kV lines along a common right of way, and/or multiple generators). While controlled loss of generation or load or system separation is permitted in certain circumstances, their uncontrolled loss is not permitted (WECC 2001).
- Western "General Requirements for Interconnection," September 1999, provides Western's general minimum requirements including technical, environmental and contractual requirements for interconnection, additions and modifications to Western's transmission facilities.
- California Public Utilities Commission (CPUC) General Order 95 (GO-95), "Rules for Overhead Electric Line Construction," formulates uniform requirements for

construction of overhead lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance and operation or use of overhead electric lines and to the public in general.

- CA ISO Planning Standards also provide standards, and guidelines to assure the adequacy, security and reliability in the planning of the CA ISO transmission grid facilities. The CA ISO Planning Standards incorporate the merged NERC and WECC Planning Standards. With regard to power flow and stability simulations, the CA ISO Planning Standards are similar to NERC/WECC and the NERC Planning Standards for Transmission System Contingency Performance. However, the CA ISO Standards also provide some additional requirements that are not found in the NERC/WECC or NERC Planning Standards. The CA ISO Standards apply to all participating transmission owners interconnecting to the CA ISO controlled grid. It also applies when there are any impacts to the CA ISO grid due to facilities interconnecting to adjacent controlled grids not operated by the CA ISO (CA ISO 2002a).
- CA ISO/FERC Electric Tariff provides guidelines for construction of all transmission additions/upgrades (projects) within the CA ISO controlled grid. The CA ISO determines the "Need" of the proposed project where it will promote economic efficiency or maintain System Reliability. The CA ISO also determines the Cost Responsibility of the proposed project and provides an Operational Review of all facilities that are to be connected to the CA ISO grid.

TSE ATTACHMENT 2: DEFINITION OF TERMS

ACSR	Aluminum Cable Steel Reinforced.
SSAC	Steel Supported Aluminum Conductor
AAC	All Aluminum conductor.
ADR	Alternative Dispute Resolution
Ancillary Services Market	The market for services other than scheduled energy that are required to maintain system reliability and meet WSCC/NERC operating criteria. Such services include spinning, non-spinning, replacement reserves, regulation (AGC), voltage control and black start capability.
Ampacity (Amps)	Current-carrying capacity, expressed in amperes, of a conductor at specified ambient conditions, at which damage to the conductor is nonexistent or deemed acceptable based on economic, safety, and reliability considerations.
Amperes or Amps	The unit of measure of electric current; specifically, a measure of the rate of flow of electrons past a given point in an electric conductor such as a power line.
Available Transmission Capacity (i.e., ATC)	Available Transmission Capacity in any hour is equal to Operational Transmission Capacity for that hour minus Existing Transmission Contracts for that same hour (ATC = OTC - ETC). (See the other definitions below).
Breaker	Circuit breaker - An automatic switch that stops the flow of electric current in a suddenly overloaded or otherwise abnormally stressed electric circuit.
Bundled Conductor	Two or more wires, connected in parallel through common switches, that act together to carry current in a single phase of an electric circuit.
Bus	Conductors that serve as a common connection for multiple transmission lines.
CA ISO	California Independent System Operator - The CA ISO is the FERC regulated control area operator of the CA ISO transmission grid. Its responsibilities include providing non-discriminatory access to the grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The CA ISO has no affiliation with any market participant.

CA ISO Controlled Grid	The combined transmission assets of the Participating Transmission Owners (PTOs) that are collectively under the control of the CA ISO.
CA ISO Reliability Criteria	Reliability standards established by the NERC, WSCC, and the ISO, as amended from time to time, including any requirements of the NRC.
CA ISO Planning Process	Annual studies conducted by the PTO's and CA ISO in an open stakeholder process. These studies determine the future transmission reinforcements necessary to enable the ISO Controlled Grid to meet the ISO Reliability Criteria. The CA ISO Planning Process also includes studies of new resource connections and third party proposals for new additions to the ISO Controlled Grid.
CA ISO Tariff	Document filed with the appropriate regulatory authority (FERC) specifying lawful rates, charges, rules, and conditions under which the utilities provide services to parties. A tariff typically includes rate schedules, list of contracts, rules, and sample forms.
Capacitor	An electric device used to store charge temporarily, generally consisting of two metallic plates separated by a dielectric.
Cogeneration	The consecutive generation of thermal and electric or mechanical energy.
Conductor	The part of the transmission line (the wire) which carries the current.
Congestion	The condition that exists when market participants seek to dispatch in a pattern which would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules.
Congestion Management	Congestion management is a CA ISO scheduling protocol that is used to resolve Congestion.
Contingency	Disconnection or separation, planned or forced, of one or more components from the electric system.
Day-Ahead Market	The forward market for the supply of electrical power at least 24 hours before delivery to Buyers and End-Use Customers.
Demand	Load plus any exports from an electric system.

Demand Forecast	An estimate of demand (electric load) over a designated period of time.
Dispatch	The operating control of an integrated electric system to: (i) assign specific generators and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises of falls; (ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; (iii) operate interconnections (iv) manage energy transactions with other interconnected Control Areas; and (v) curtail Demand.
dV/dQ	The partial derivative of the voltage at a bus with respect to the reactive injection at that bus. (See any elementary college calculus text for further discussion of partial derivatives.) The point at which dV/dQ approaches infinity is defined as the point of voltage collapse.
Emergency Condition	The system condition when one or more system elements are forced (not scheduled) out of service.
Emergency Overload	Loading of a transmission system element above its Emergency Rating during an Emergency Condition.
Emergency Rating	A special rating established for short-term use in the event of a forced line or transformer outage (e.g., an emergency). An emergency rating may be expressed as a percentage of the normal rating (e.g., 115 percent of normal) or as an elevated current rating. For example, the normal rating for a conductor may be 1000 amperes and the emergency rating may be 1100 amperes.
Excessive Voltage Deviation	A sudden change in voltage at any substation as a result of a Contingency that exceeds established allowable levels of change.
Existing Transmission Contract (i.e., ETC)	A contract for transmission services that was in place prior to the start of ISO operations.
Fault Duty	The maximum amount of short-circuit current which must be interrupted by a given circuit breaker.
FERC	Federal Energy Regulatory Commission
General Order 95	California Public Utilities Commission (CPUC) General Order which specifies transmission line clearance requirements.
Generation Outlet Line	Transmission facilities (circuit, transformer, circuit

breaker, etc.) linking generation to the main grid.

Generation Tie	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation to the main grid.
Generator	A machine capable of converting mechanical energy into electrical energy.
Heat Rate	The amount of energy input to an electric generator required to obtain a given value of energy output. Usually expressed in terms of British Thermal Units per kilowatt hour (Btu/kWh).
Hour-Ahead Market	The electric power futures market that is established 1-hour before delivery to End-Use Customers.
Imbalance Energy	Energy not scheduled in advance that is required to meet energy imbalances in real-time. This energy is supplied by Participating Generators under the CA ISO's control, providing spinning and non-spinning reserves, replacement reserves, and regulation, and other generators able to respond to the CA ISO's request for more or less energy.
Interconnected System Reliability	See Reliability.
Kcmil or kcm	One thousand circular mils. A unit of the conductor's cross sectional area which, when divided by 1,273, gives the area in square inches.
kV	Kilovolt - A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground.
Load	The rate expressed in kilowatts, or megawatts, at which electric energy is delivered to or by a system, or part of a system to end use customers at a given instant or averaged over an designated interval of time. (Also see Demand.)
Load Factor	The average Load over a given period (e.g., one year) divided by the peak Load in the period.
Loop	An electrical connection where a line is opened and a new substation is inserted into the opening. A looped configuration creates two lines, one from each of the original end points to the new substation. A looped configuration is more reliable than a tap configuration because the looped configuration provides two lines into the substation rather than just one in a tap configuration. Also, see Tap below.

Low Voltage	Voltage at any substation that is below the minimum acceptable level.
Marginal Unit	The Generator (or Load) that sets the market clearing price in the ISO's Ancillary Services Market (or the Power Exchange's energy market). The marginal unit is the Generator or Load that had the highest accepted bid for energy or Demand reduction.
MVAr	Megavar - One megavolt ampere reactive (a measure of reactive power). Reactive power demand is generally associated with motor loads and generation units or static reactive sources must supply this demand in the system.
MVA	Megavolt ampere - A unit of apparent power: equal to the product of the line voltage in kilovolts, the current in amperes, and the square root of 3 divided by 1000.
MW	Megawatt - A unit of power equivalent to 1,341 horsepower.
NERC	North American Electric Reliability Council
Nominal Voltage	Also known as Normal Voltage. The voltage at which power can be delivered to loads without damage to customer equipment or violation of CA ISO Reliability Criteria when the system is under Normal Operation.
Normal Operation	When all customers receive the power they are entitled to without interruption and at steady voltage, and no element of the transmission system is loaded beyond its continuous rating.
NRC	Nuclear Regulatory Commission
N-1 Contingency	A forced outage of one system element (e.g., a transmission line or generator).
N-2 Contingency	A forced outage of two system elements usually (but not exclusively) caused by one single event. Examples of an N-2 Contingency include loss of two transmission circuits on a single tower line or loss of two elements connected by a common circuit breaker due to the failure of that common breaker.
Operational Transfer Capability (i.e., OTC)	The maximum amount of power which can be reliably transmitted over an electrical path in conjunction with the simultaneous reliable operation of all other paths. This limit is typically defined by seasonal operating studies, and should not be confused with a path rating. Also referred to as

	OTC.
Outlet	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation to the main grid.
Participating Generator	A generator that has signed an agreement with the CA ISO to abide by the rules and conditions specified in the CA ISO Tariff.
Participating Transmission Owner (i.e., PTO)	A Participating Transmission Owner is an electric transmission owning company that has turned over operational control of some or all of their electric transmission facilities to the CA ISO. Currently, the three Participating Transmission Owners are PG&E, SCE, and SDG&E.
Path Rating	The maximum amount of power which can be reliably transmitted over an electrical path under the best set of conditions. Path ratings are defined and specified in the WSCC Path Rating Catalog.
PG&E	Pacific Gas & Electric Company
PG&E Interconnection Handbook	Detailed instructions to new customers (either load or generation) on how to interconnect to the PG&E electric system.
Post-Transient Voltage Deviation	The change in voltage from pre-contingency to post-contingency conditions once the system has had time to readjust.
Power Flow	A generic term used to describe the type, direction, and magnitude of actual or simulated electrical power flows on electrical systems.
Power Flow Analysis	A power flow analysis is a forward looking computer simulation of all major generation and transmission system facilities that identifies overloaded circuits, transformers and other equipment as well as system voltage levels under both Normal and Emergency Conditions.
Pump	A hydroelectric generator that acts as a motor and pumps water stored in a reservoir to a higher elevation.
Q/V Curve	A graphical representation of the voltage a given substation bus as a function of the reactive injection at that bus.
RAS	Remedial Action Scheme - An automatic control provision (e.g., trip a generation unit to mitigate a circuit overload).

Reactive Power	The portion of apparent power that does no work in an alternating current circuit but must be available to operate certain types of electrical equipment. Reactive Power is most commonly supplied by generators or by electrostatic equipment, such as shunt capacitors.
Reactive Margin	Reactive Power must be available at all load buses to prevent voltage collapse. Reactive margin is the amount of additional reactive load, usually measured in MVAR's, which may be added at a particular bus before the system experiences voltage collapse.
Reactor	An electric device used to store electric current temporarily, generally consisting of a coil of wire wound around a magnetic core.
Real Power	Real power is the work-producing component of apparent power and is required to operate any electrical equipment that performs energy conversion. Examples of this electrical equipment would be a heater, a lamp, or a motor. Real power is usually metered in units of kilowatt-hours (kWh).
Real-Time Market	The competitive generation market controlled and coordinated by the CA ISO for arranging real-time imbalance power.
Reconductoring	The removal of old conductors on a transmission or distribution line followed by replacement of these conductors with new higher capacity conductors.
Reliability	The degree of performance of the elements of the electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. May be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.
Reliability Criteria	Principals used to design, plan, operate, and assess the actual or projected reliability of an electric system.
Reliability Must-Run (i.e., RMR)	The minimum generation (number of units or MW output) required by the CA ISO to be on line to maintain system reliability in a local area.

SCE Transmission Owner Tariff	Provides guidelines to interconnect SCE System to a generator or to construct transmission expansions and facilities upgrades.
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
Sensitivity Study	An analysis to determine the impact of varying one or more parameters on the results of the original analysis.
Series Capacitor	A static electrical device that is connected in-line with a transmission circuit that allows for higher power transfer capability by reducing the circuit's overall impedance.
Shunt Capacitor	A static electrical device that is connected between an electrical conductor and ground. A shunt capacitor normally will increase the voltage on a transmission circuit by providing reactive power to the electrical system.
Single Contingency	See N-1 Contingency.
Solid Dielectric Cable	Copper or aluminum conductors that are insulated by solid polyethylene type insulation and covered by a metallic shield and outer polyethylene jacket.
Source or Sink of Reactive Power	A source of Reactive Power is a device that injects reactive power into the power system (e.g., a Generator or a Capacitor). A sink of Reactive Power absorbs reactive power from the power system. Examples of reactive power sinks are shunt Reactors and motor loads.
Static Compensator	StatCom - a shunt connected power system device that includes Capacitors and Reactors controlled by solid state electronic devices as opposed to mechanically operated switches.
Substation	An assemblage of equipment that switches, changes, or regulates voltage in the electric transmission and distribution system.
Switchyard	A substation that is used as an outlet for one or more electric generators.
Switched Reactive Devices	A shunt Capacitor or shunt Reactor controlled by mechanically operated switches.
Switching Station	Similar to a substation, but there is only one voltage level.

Synchronous Condenser	A rotating mechanical device very similar to a Generator. The Synchronous Condenser has no mechanical power input and cannot produce Real Power. It can only produce or absorb Reactive Power.
System Reliability	See "Reliability".
Tap	An electrical connection where a new line is connected to an intermediate point on an existing transmission line and a new substation is connected to the end of the new line. A tapped configuration creates a single transmission circuit with more than two end points (for example, a "T"). A tapped configuration is less reliable than a looped configuration because a fault on any portion of the tapped circuit causes a complete loss of power to the new substation. Also, see Loop above.
Tap Changing Transformer	A Transformer that has the ability change the number of windings in service. By changing the number of windings in service (by moving to a different tap), the Tap Changing Transformer has the ability to maintain a nearly constant voltage at its output terminals even though the input voltage to the Transformer may vary.
Thermal Loading Capability	The current-carrying capacity (in Amperes) of a conductor at specified ambient conditions, at which damage to the conductor is non-existent or deemed acceptable based on economic, safety, and reliability considerations.
Thermal overload	A thermal overload occurs when electrical equipment is operated in excess of its current carrying capability. Overloads are generally given in percent. For example, a transmission line may be said to be loaded to 105 percent of its rating.
Thermal rating	See Ampacity.
Transformer	A device that changes the voltage of alternating current electricity.
Transformer Loading Capability	The current-carrying capacity (in Amperes) of a transformer at specified ambient conditions, at which damage to the transformer is non-existent or deemed acceptable based on economic, safety, and reliability considerations.
TSE	Transmission System Engineering.
Underbuild	A transmission or distribution configuration where a

	transmission or distribution circuit is attached to a transmission tower or pole below (under) the principle transmission line conductors.
Undercrossing	A transmission configuration where a transmission line crosses below the conductors of another transmission line, generally at 90 degrees.
VAr	One Volt ampere reactive. Also see the definition for MVAr.
Voltage	Electromotive force or potential difference.
Voltage Collapse	The point at which the reactive demand at a substation bus exceeds the reactive supply at that bus. When the reactive demand is greater than the supply, the voltage at that point in the system will drop. Eventually, the voltage will drop to a point at which it is no longer possible to serve load at that bus.
Wheeling	A service provided by an entity, such as a utility, that owns transmission facilities whereby it receives electric energy into its system from one party and then uses its system to deliver that energy to a third party. The wheeling entity is usually paid a fee for this service.
WESTERN	Western Area Power Administration
WATTS	Western Arizona Transmission System Task Force
WECC	Western Electric Coordinating Council