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Mr. Paul Kramer
California Energy Commission
Systems Assessment and Facilities Siting Division
1516 9th Street
Sacramento, CA 95814-5504

RE: Applicants Rebuttal Testimony
Ivanpah Solar Electric Generating System (07-AFC-5)

Dear Mr. Kramer:

On behalf of Solar Partners I, LLC, Solar Partners II, LLC, Solar Partners IV, LLC, and Solar Partners VIII, LLC, please find attached the Applicant's Rebuttal Testimony.

Please call me if you have any questions.

Sincerely,

CH2M HILL

John L. Carrier

John L. Carrier, J.D.
Program Manager

Enclosure
c: POS List
Project File

Ivanpah Solar Electric Generating System (ISEGS)

(07-AFC-5)

Applicant's Rebuttal Testimony

Submitted to the

California Energy Commission

Submitted by

Solar Partners I, LLC; Solar Partners II, LLC; Solar Partners IV, LLC; and Solar Partners VIII, LLC

January 5, 2010

With Assistance from

CH2MHILL

2485 Natomas Park Drive
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Contents

Alternatives

I. Introduction

A. Name: John Carrier, Steve De Young, Gary Rubenstein, Steve Hill, Tom Priestley, Geoffery Spaulding, Arne Olson and Roger Gray

B. Qualifications: The panel's qualifications are as noted in their resumes contained in Appendix A of Applicant's Initial Testimony submitted on November 16, 2009. Resumes for those not included in the Initial Testimony are attached as Appendix B.

C. Prior Filings: In addition to the statements herein, this testimony includes by reference the following documents submitted in this proceeding; these documents are in addition to those previously submitted with Applicant's Initial Testimony:

- Barnes, B./Cleantech America, Inc., Hunt, T./Community Environmental Council, Lewis, C./GreenVolts. 2008. Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent. March 6, 2008. [Exhibit 70].
- Black & Veatch. 2009. Re-DEC Working Group Meeting. Potential Challenges to High Penetration of Distributed Renewable Generation. December 9, 2009. [Exhibit 71]
- California Public Utilities Commission. 2008. Annual Report. 2008. Available at: ftp://ftp.cpuc.ca.gov/OGA/reports/CPUC%202008%20Annual%20Report%20Jan%2030,%202009.pdf [Exhibit 72]
- Croft, Brian/USFWS. 2009. Email communication with Susan Sanders Regarding Desert Tortoise Translocation. August 18. [Exhibit 73]
- North American Electric Reliability Corporation (NERC). 2009. Special Report: Accommodating High Levels of Variable Generation. April 2009. [Exhibit 74]
- Pacific Gas and Electric Company. 2009. Pacific Gas and Electric Company's Comments on the Energy Division's 33% RPS Implementation Analysis Preliminary Results. August 28, 2009. [Exhibit 75]
- San Diego Gas & Electric. SDG&E Response to Questions on 33% RPS Implementation Analysis Preliminary Results Report. [Exhibit 76]
- Schlesinger, W.H., J. Belnap, and G. Marion. 2009. On carbon sequestration in desert ecosystems. Global Change Biology 15: 1488-1490. [Exhibit 77]
- Southern California Edison. 2009. Southern California Edison Company's (U 338-E) Comments on, and responses to technical questions regarding, The Energy Division's 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results. July 4, 2009. [Exhibit 78].

- U.S. Department of Energy (DOE) 2009. High Penetration Solar Deployment Projects. http://www1.eere.energy.gov/solar/high_penetration.html . Accessed on January 4, 2010. [Exhibit 79]
- Wiser, R., G. Barbose, C. Peterman, and N. Darghouth. 2009. Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008" LBNL-2674E. October 2009 [Exhibit 80].

D. Documents Entered as Exhibits by Others: The following documents were cited in this testimony, but have been previously entered as exhibits by other parties.

- Wohlfahrt, G. L. Fenstermaker, and J. Arnone III. 2008. Large annual net ecosystem CO_2 uptake of a Mojave Desert ecosystem. Global Change Biology. 14:1475-1487. [CNPS Exhibit 1008]

To the best of our knowledge, all of the facts contained in this testimony (including all referenced documents) are true and correct. To the extent this testimony contains opinions, such opinions are our own. We make these statements, and render these opinions freely and under oath for the purpose of constituting sworn testimony in this proceeding.

II. Summary of Rebuttal Testimony

A. I-15 Alternative Location

This portion of the rebuttal testimony addresses the direct testimony of Scott Cashen. Mr. Cashen offers the results of a field survey that purports to show that the I-15 has fewer impacts to the desert tortoise than the project site. However, Mr. Cashen's survey is deeply flawed and must be rejected.

First, Mr. Cashen does not identify the areas he surveyed in relation to the boundaries of the I-15 alternative site, as shown in Figure 6 of the Alternatives Section of the FSA. Therefore, it is not possible to determine whether the area he surveyed is within the boundaries of the I-15 site or not. He states that the FSA does not precisely define the boundaries of the I-15 site and that the site assessment he conducted "encompassed areas that we believed extended beyond the alternative site's boundaries." (Sierra Club's Opening Testimony, p. 20) However, he fails to indicate which areas he surveyed extended beyond the boundaries of the I-15 alternative.

Second, Mr. Cashen appears to have surveyed a long and narrow transect immediately adjacent to and parallel to the north side of I-15 near the Yates Well Road exit. However, Figure 6 of the Alternatives Section of the FSA appears to show that the I-15 alternative is separated from I-15 by approximately one quarter mile. Prior Traffic and Transportation testimony indicated that the project must be located at least 1000 meters from I-15 to avoid glare issues; therefore, this area adjacent to I-15—as surveyed by Mr. Cashen—is clearly outside the boundaries of any proposed alternative. Moreover, the area surveyed by Mr. Cashden appears to include the site of the proposed Caltrans Port of Entry Project.

Third, Mr. Cashen reflects extreme bias in the selection of the transects immediately adjacent to I-15. Despite emphasizing the importance of habitat characteristics including elevation, Mr. Cashen fails to demonstrate that these results are controlled for bias in his selection of the transects and habitat type to be surveyed. In the vicinity of I-15 there is tortoise habitat that is of higher quality at higher elevation (nearer the Nipton Road exit) and comparatively lower quality at lower elevation (nearer the golf course and the Yates Well Road exit). Selection of the transect immediately adjacent to I-15 was skewed to the lower elevation, lower quality habitat and to the area immediately adjacent to I-15 that is not representative of the entire I-15 alternative.

Fourth, the survey was apparently conducted by a group of untrained amateurs. Mr. Cashen's fieldwork was performed by "a survey crew consisting of eight members of American Conservation Experience (ACE)." (Sierra Club's Opening Testimony at 9) According to the ACE website, "Volunteers need no experience in practical conservation. The only requirements are a sense of adventure, a desire to make a difference, and a willingness to remain flexible and positive through ever changing project work, locations, and weather conditions."[1] It does not appear that these volunteers were trained biologists and their resumes were not provided.

Fifth, despite the bias of the selected transects and the inexperience of the survey team, portions of the area surveyed by Cashen would not have lower impacts than the project site. He concludes that a portion of the area he surveyed should be avoided by the project, but he fails to identify the area to be avoided with any specificity. (Sierra Club's Opening Testimony at 20)

Sixth, Mr. Cashen surveyed only for tortoise burrows. He did not survey for any other plants or animals, so the survey does not add to an understanding of these species. Instead, Mr. Cashen bases his conclusions regarding the potential impacts to other resources solely on his selective review of the literature.

In addition to the above described fundamental flaws in Mr. Cashen's purported survey of the I-15 alternative, we have the following comments regarding his testimony.

Mr. Cashen contends that the FSA devoted insufficient time and resources to site comparisons for the I-15 alternative. (Sierra Club's Opening Testimony, p. 7) The approximately 11 square miles (7,128 acres) referenced in his testimony, including the areas close to I-15, received study by dozens of the Applicant's biologists and field staff over an approximately 2-year period (Supplemental Data Response Set 1D, [Exhibit 35]). These included wildlife biologists and botanists as well as plant and restoration ecologists. While the I-15 corridor area did not receive as intensive a level of study as the preferred project area, its vegetation and habitat qualities are sufficiently understood to allow informed comparisons.

Although Mr. Cashen notes that habitat variables were collected, in section I.B. of his testimony he appears to assume these variables were not considered in the FSA. (Sierra Club's Opening Testimony, pp. 7-8) This is an incorrect assumption. Variables considered by the Applicant included precipitation, and it was noted that the quality of habitat in the vicinity of the I-15 corridor ranged from less-than-optimum at relatively low elevations to diverse and relatively productive desert scrub at higher elevations. [Ex. 28] This is largely a function of effective moisture (orographically induced precipitation combined with elevationally dependent evapotranspiration rates). Related effects on tortoise carrying capacity were of course considered in the FSA (at 6.2-50) and confirmed by USFWS [Exhibit 72].

On page 8 of his testimony, Mr. Cashen confuses the widely accepted definitions of "niche" and "habitat." Generally, a thorough characterization of its "habitat" satisfies the need to describe the physiographic/physiological aspect of an organism's environmental requirements. That

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[1] http://www.usaconservation.org/Volunteer/FAQs.html#need_experience

habitat characterization is informed by an understanding of the species' niche (the area it occupies in n-dimensional ecological space). No critically important descriptive component or aspect of the desert tortoise' habitat or niche has been ignored or overlooked in the Applicant's evidence.

On page 14 of Mr. Cashen's testimony, in item 2 he says that "The FSA failed to report that no desert tortoises were reported within the action area during the development of the Primm Valley Golf Club." The source for that statement was the Draft Biological Assessment prepared by the Applicant on behalf of BLM. That Biological Assessment did not include any information about the "development of the Primm Valley Golf Club."

Mr. Cashen also states that, "the Primm Valley Golf Club is located immediately adjacent to the I-15 alternative site; it occupies a similar range of elevations as the I-15 site . . ."This statement is also incorrect because the Golf Club is lower in elevation near the barren valley-bottom playa; whereas, the I-15 site (as shown in Alternatives Figure 6 of the FSA) ranged from a low elevation similar to that of the Golf Club, to a much higher elevation on its western end near Nipton Road.

On page 17, Mr. Cashen based his conclusion about the likelihood of Mojave milkweed occurring in the I-15 alternative site on a statement on page 4-44 of the FSA that "Atriplex scrub [is] one of the two dominant habitat types present on the I-15 alternative site." This statement in the FSA is incorrect. Atriplex scrub is not common across the I-15 alternative site. In fact, during the reconnaissance survey of a 1-mile-wide buffer area around the project site, which was performed by the Applicant in 2007, we did not find any Atriplex scrub within the portion of the 1-15 Alternative that was within the 1-mile buffer surrounding Ivanpah 1. The one-mile buffer surveys were not protocol-level surveys, instead the surveyors used a "meandering walk" technique to visually observe vegetation types, and look for rare plants on a presence-absence basis. The one-mile buffer survey boundary is shown in Figure 1-1 of the Ivanpah SEGS rare plant report (Supplemental Data Response Set 1D, [Exhibit 35]), which appears to overlap about half of the I-15 alternative.

Mr. Cashen's habitat descriptions for rare plants comes straight out of the literature, and does not take into account what was found at the Ivanpah SEGS site. What was found as a result of protocol surveys expanded the range for habitats and elevations for most of the rare plant species that were found. What can be concluded is that the habitats, elevational ranges, and geographic distributions of these species are not very well known, so using what is in the literature to predict what may or may not be within the I-15 Alternative site is pure speculation.

B. Carbon Sequestration

The California Native Plant Society (CNPS) and Defenders of Wildlife (DOW) comment that the FSA/DEIS fails to identify and analyze the loss of carbon sequestration function that will occur under the proposed project. They cite the findings of Wohlfahrt et al. (2008) [CNPS Exhibit 1008] in asserting that Ivanpah SEGS and all desert utility-scale projects to follow will decrease the carbon sequestration benefits from desert vegetation. While Wohlfahrt et al. (2008) offers a valuable perspective into the nature of carbon flux in a Mojave Desert scrub community, it hardly provides a secure basis to assert that a large net negative flux (carbon sequestration) occurs in their study area, much less elsewhere in the Mojave Desert.

A substantial proportion of the analyses by Wohlfahrt et al. (2008) is directed at treating the inherent uncertainty of their data. Standard deviations for their originally calculated values of CO_2 flux are enormous (exceeding 50 percent of the mean at 1σ): -102 ± 67 to -110 ± 70 g C m^{-2} yr^{-1}. [Ex. 1008 at 1482] At two standard deviations the measured flux could be positive (net carbon loss). Wohlfahrt et al. (2008) marshal a range of statistical treatments addressing both atmospheric dynamics as well as instrumental uncertainties, and cite a number of studies providing qualitative support for their conclusion that negative net flux (carbon sequestration) occurs in their desert scrub study site. If their proposed flux rates actually reflected sequestration, then hundreds of kg of C would have been sequestered in each square meter of desert soils during the current interglacial. To our knowledge no such carbon reservoir in desert soils has been identified to date.

The results reported by Wohlfahrt et al. (2008) have likewise been questioned by Schlesinger et al. (2009) [Exhibit 77]. Schlesinger et al. note that the net carbon uptake reported by Wohlfahrt et al. is dramatically greater than the net primary production (NPP) at a nearby Nevada site and in other creosotebush shrublands in the desert southwest. Even after considering the potential carbon storage potential of biological crusts, the net carbon uptake values that were reported are simply not realistic. However, if such a rate of carbon uptake were occurring, it should have been reflected in net carbon storage in the ecosystem; in the absence of measured changes in carbon storage, then equally great carbon losses would be presumed (Schlesinger et al., 2009) [Ex. 77]. Because no mechanisms for such substantial carbon loss have been identified, the Wohlfahrt results were further questioned (Schlesinger et al., 2009) [Ex. 77].

In addition to the concerns described above, applying results of the Wohlfahrt study to different localities can be problematic. The study area of Wohlfahrt possesses soils that are loamy sands typically covered with a cryptogam crust. They attribute most of this carbon accretion to the expansion and growth of cryptobiotic organisms (lichens, mosses, cyanobacteria) on the structureless soil. While the primary soils in the Ivanpah SEGS site are also characterized as loamy sands (i.e., Arizo loamy sand, 2 to 8 percent slopes), there are few areas possessing a cryptobiotic crust, reflecting the generally degradational erosional regime of the Ivanpah SEGS site. Therefore, experimental, biological, and geographic issues should be resolved before the findings of Wohlfahrt et al. (2008) can be confidently applied to the Ivanpah SEGS site. Within the limits of the data currently available, the Ivanpah SEGS site likely sequesters considerably less CO_2 per unit area than is suggested by the CNPS and DOW.

In addition, it should be considered that electricity produced by Ivanpah SEGS will displace power produced by other sources. It will not displace baseload production, nor will it displace energy generated by “must take” facilities. The production that will be displaced is the production that would have been dispatched if the Ivanpah SEGS power had not been dispatched instead.

The displaced production will always be fossil-fuel derived. At peak periods, Ivanpah SEGS’s power will reduce the need to operate peaking power plants, which are generally the least efficient facilities. Most of the Ivanpah SEGS power will, however, displace intermediate sources of power. The following calculations are based on the conservative assumption that Ivanpah SEGS will displace the lowest-emitting fossil fuel-fired power plants in the system—modern gas-fired combined-cycle power plants. The assumption is conservative because, as discussed above, some of the displaced power production would have come from less efficient sources.

The following table shows the power production rates used to make the displacement calculations.

TABLE ALT-1
ISEGS Power Production (MW-hrs)

	Hour	Day	Year
Ivanpah SEGS Production	400	4,000	1,440,000

The following table shows the greenhouse gas (GHG) displacement of Ivanpah SEGS relative to modern gas-fired combined-cycle power plants—the plants most likely to be displaced by the project.

TABLE ALT-2
GHGs Displaced by Using Solar Instead of Natural Gas

		MTCO2eq Displaced per Unit Time		
	MTCO2eq/MWHR	Hour	Day	Year
Standard power plant[a]	0.5	188	1,884	678,240
Modern gas-fired combined-cycle plant[b]	0.383	142	1,416	509,760
Ivanpah SEGS	0.029	—	—	—

Sources:
[a]The standard is set by CEC regulation (CCR Chapter 11 Art 1 sec 2902)
[b]Final Commission Decision for the Avenal Power Plant (08-AFC-1), p. 112

Carbon Uptake by the Mojave Desert Biosystem

As described above, Wohlfahrt et al. (2008) measured net CO_2 uptake in the Mojave Desert over a 2-year period. Using his measurements, which, as discussed above, the Applicant does not think apply to the Ivanpah SEGS area, carbon uptake would be approximately 105 ± 70 g C/m^2/yr, or 1.56 MTCO2 eq/acre/year. If this uptake rate is applied to the 4,060 acres of the Ivanpah SEGS project, the total carbon uptake would be 6,326 metric tons of CO_2 equivalent per year (MTCO2eq/yr). Therefore, using Wohlfahrt's data, Ivanpah SEGS would displace more than 80 times as much fossil-fuel GHGs than the land it sits on will sequester if all vegetation is removed from the 4,060-acre site and carbon is sequestered at the rate that Wohlfahrt suggests. Further, if we conservatively assume that half of the vegetation will remain, Ivanpah SEGS would displace more than 160 times as much fossil-fuel GHGs than the vegetation would sequester at Wohlfahrt's rates.

C. Photovoltaics

C1. The following testimony is offered by Arne Olson

Introduction and Overview

Q. Please state your name and business affiliation.

A. My name is Arne Olson. I am a partner at Energy and Environmental Economics, Inc. (E3) located at 101 Montgomery Street, Suite 1600, San Francisco, California, 94104.

Q. What is the purpose of your rebuttal testimony?

A. I was retained by BrightSource Energy to rebut the testimony of Mr. Bill Powers, filed on the behalf of the Center for Biological Diversity (CBD), which takes issue with the Final Staff Assessment's (FSA) conclusion that distributed photovoltaic power is not a viable alternative to the Ivanpah Solar Electric Generating Station (ISEGS).

Q. Please describe your professional experience and qualifications in connection to your rebuttal testimony herein.

A. I have over 15 years of experience in the energy industry, the last eight as a Senior Consultant and then Partner at E3 where I have contributed to many studies regarding renewable energy cost and potential in California and the West. In addition, I am directly familiar with many of the issues raised in Mr. Powers' testimony. I was the lead consultant for the California Public Utilities Commission's 33% RPS Implementation Analysis (found at http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm), which studied the cost and likelihood of bringing online sufficient renewable energy to meet a 33% Renewables Portfolio Standard (RPS) by 2020, cited a number of times in Mr. Powers' testimony (e.g., p. 10). I was also the principal author of the 33% RPS Calculator, the model used to calculate the cost impacts reported in that study.

I am currently advising the California Public Utilities Commission (CPUC) Energy Division on its Long-Term Procurement Planning (LTPP) proceeding, including performing a "Renewables and Transmission Study" for use in the 2010 LTPP proceeding. In my role as advisor to the Energy Division, I have advocated that the state begin to study in a serious way the potential to meet large portions of the state's renewables need with distributed PV resources. In that spirit, I encouraged both the creation of the CPUC's Transmission-Constrained Working Group (which has since evolved into Re-DEC, the Renewable Distributed Energy Collaborative) and the inclusion of the High DG case among the cases that the CPUC's 33% RPS study considered.

In addition, I have participated in a number of studies of the cost and technical feasibility of increased reliance on both distributed and central station renewable energy resources, including distributed PV. For example, I participated in a study of distributed alternatives to the Kangley-Echo Lake transmission line proposed by the Bonneville Power Administration. I also co-authored a study of potential westwide transmission infrastructure requirements under aggressive RPS and greenhouse gas (GHG) reduction scenarios for the Western Electric Industry Leaders' Group, composed of executives of numerous electric utilities in the Western Interconnection.

I have a Master of Science degree in Energy Management and Policy from the University of Pennsylvania and Bachelor of Science degrees in Mathematical Sciences and Statistics from the University of Washington.

Q. Please summarize your testimony.

A. My testimony finds that the Commission should reject Mr. Powers' recommendation that distributed photovoltaic (DPV) energy be considered a viable alternative to ISEGS. This finding stems from the following conclusions:

- First, Mr. Powers' recommendation is illogical and the Commission's accepting it would have in a number of very serious and far-reaching policy implications.
- Second, Mr. Powers wrongly concludes that demonstrating the feasibility to interconnect only 400 MW of DPV is sufficient to reject ISEGS on the sole basis that ISEGS is a central station, and not a distributed technology. In fact, Mr. Powers would need to demonstrate the technical and economic feasibility of interconnecting over 37,000 MW of DPV in order for DPV to be considered a viable alternative to ISEGS.
- Third, Mr. Powers' testimony does not present any convincing evidence that there is 37,000 MW of DPV potential in California.
- Fourth, Mr. Powers' testimony does not present any evidence that it is technically feasible to interconnect 37,000 MW of DPV while maintaining reliable grid operations.
- Finally, Mr. Powers' testimony does not present any convincing evidence that DPV is more cost-effective than central station PV and solar thermal resources.

Q. How is your testimony organized?

A. My testimony is organized into four sections.

- Section 1 discusses Mr. Powers' recommendations and explains their far-reaching implications for this and future central station generation applications that the Commission may consider as well as the Commission's support for other energy planning efforts.
- Section 2 explains the important differences between distributed photovoltaic (DPV) and utility-scale photovoltaic (UPV) installations. It also demonstrates that Mr. Powers assumes the two applications are interchangeable and, as a result, arrives at a number of erroneous conclusions.
- Section 3 shows that Mr. Powers testimony likely overstates the technical potential of DPV.
- Section 4 demonstrates that Mr. Powers' testimony likely understates the cost of DPV relative to UPV and solar thermal.

1. Mr. Powers' recommendation is illogical and would have far-reaching implications for energy planning and policy in California

Q. What is Mr. Powers' recommendation?

A. Mr. Powers is asking the Commission to determine that DPV is a viable, environmentally superior and less costly alternative to ISEGS and to reject BrightSource Energy's application to construct ISEGS on this basis. He is asking the Commission to make this determination on the basis of his assertions that there is the potential to install at least 400 MW of DPV in California at a cost that is lower than ISEGS.

Q. Is Mr. Powers asking the Commission to conclude that PV is a superior technology to ISEGS at the same location?

A. No, he is not. Mr. Powers takes no issue with the FSA's conclusion that other solar technologies, including PV, "would not substantially change the severity of visual impacts or biological resources impacts" relative to the power tower technology proposed for ISEGS. Mr. Powers' testimony focuses exclusively on the possibility of siting 400 MW of distributed PV.

Q. Does Mr. Powers propose a specific site for the 400 MW of DPV resources?

A. No, he does not. Instead, it asks the CEC to find that: (a) DPV is a superior alternative based on the sole criterion that it is distributed; and (b) any 400 MW of DPV potential anywhere in California is sufficient grounds to reject BSE's application for ISEGS.

Q. Is Mr. Powers' recommendation logical in light of your experience in renewable resource planning?

A. No, it is not. If the Commission finds that ISEGS is not needed because there is the potential to build 400 MW of DPV somewhere in California, then the Commission will be unable to approve the applications of any central station generation for the foreseeable future. Opponents of the next central station generation will use the same argument about the same 400 MW of DPV potential. The same 400 MW of DPV potential would, in turn, be used to as a justification for rejecting the need for every central station generation application that comes before the Commission.

Q. What quantity of generic DPV would constitute a meaningful alternative to ISEGS?

A. California's renewables "gap" for meeting 33% RPS by 2020 has been variously cited at between 59,000 GWh (RETI Phase 1b Report) and 75,000 GWh (CPUC 33% RPS Implementation Analysis). In order to make the blanket determination that ISEGS is not needed solely because it is a central station and not a distributed technology, the Commission must find that it is technically feasible, economically feasible and in the public interest for DPV to meet all of the state's renewable resource gap of 59-75 TWh. That is, the Commission must determine that central station generation is no longer necessary to meet California's RPS and GHG goals. As long as there is a need for some central station generation, then ISEGS must be compared to other central station alternatives and not to a generic DPV alternative.

Q. What are other potential implications of the Commission accepting Mr. Powers' recommendation and finding that central station generation is no longer needed to meet California's RPS and GHG goals?

A. A finding that central station generation is no longer needed is so broad as to change nearly every aspect of energy planning in California. Important implications of the Commission making such a finding are:

- Central station solar thermal development would come to an immediate halt, since no solar thermal developer would be able to obtain financing to pursue project development if investors are not confident that it is possible to permit and site solar thermal projects in California.
- No new transmission, or at least very little new transmission, would be needed in California. The Commission should therefore cease all support for the Renewable Energy Transmission Initiative and the California Transmission Planning Group.
- The Commission's generation siting function itself would become obsolete, since DPV is not required to obtain site licenses from the Commission.
- There would be no more need to do energy planning in California because DPV would always be the preferred resource option under Powers' recommendation. The only remaining task of energy planners and policymakers would be to determine the most appropriate mechanisms to procure and pay for DPV.

Q. Is it appropriate for the Commission to make such a broad determination at this time?

A. No, it is not. It is far too early for the Commission to determine that central station generation is no longer necessary, for the following reasons:

1. It is unlikely that there is sufficient DPV potential in California to meet a resource gap of 59,000-75,000 GWh.
2. No technical studies have been conducted to indicate that it is feasible to integrate 59,000-75,000 GWh of DPV in California.
3. While the news of recent price drops in the PV industry is exciting, there is not enough data on actual PV costs at this time to determine the long-term price trend with any degree of certainty.
4. Current DPV pricing in the United States is heavily dependent on federal policy support in the form of a 30% Investment Tax Credit and accelerated depreciation benefits via 5-year Modified Accelerated Cost Recovery System.

Because there is still so much uncertainty about the feasibility and cost of a DPV-only strategy, it would be far too risky for the Commission to determine that central station generation is no longer necessary at this time. A number of studies and initiatives are currently underway to try to reduce the uncertainties about the technical feasibility of high DPV penetration. These include, most importantly, the California ISO's 33% RPS Integration Study and the CPUC's Renewable Distributed Energy Collaborative (Re-DEC). We will learn a great deal over the next few years that will help determine whether and to what extent it is in the public interest to rely more heavily on DPV in California. In the meantime, it is imperative that the state continue to develop central station technologies such as wind, geothermal, solar thermal as well as large solar PV (UPV) plants if it wishes to have any hope of meeting its 2020 renewable and greenhouse gas reduction goals.

2. Distributed PV and Utility-Scale PV are not interchangeable

Q. Please describe the key differences between DPV and UPV installations.

A. Distributed PV installations have both advantages and disadvantages relative to central station PV installations. The economic advantage of DPV over remote installations stems from their avoidance of transmission and distribution system (T&D) losses and, secondarily, their ability to defer transmission and distribution system upgrades in some circumstances. Disadvantages include the generally lower-quality solar resource in urban areas, the higher cost of land and the smaller scale of the projects. There is no universally accepted definition of "distributed" resources, but the following table summarizes some of the key distinctions between DPV and UPV installations in the context of Mr. Powers' testimony, which claims a number of benefits for distributed PV installations.

Distributed Photovoltaic (DPV) Installations	Utility-Scale Photovoltaic (UPV) Installations
Generally small in size (a few kW up to a few MW)	Can be much larger in size (2 – 500 MW)
Generally located in or near load centers	Generally located remote from load centers
Can be either ground-mounted or roof-mounted	Ground-mounted
Generally rely on fixed-tilt PV technology	May rely on either fixed-tilt or tracking technology
Interconnected to a radically configured distribution or sub-transmission system serving load "downstream", i.e., power flows from the installation directly to loads connected to the same distribution feeder and never flows back up into the sub-transmission or bulk transmission grids.	Interconnected to a networked sub-transmission or bulk transmission system, feeding power into the bulk transmission grid.
May be connected on either the customer or the utility side of the meter	Connected on the utility side of the meter
May qualify for Net Energy Metering	Do not qualify for Net Energy Metering
May not count toward meeting utility RPS requirements (if connected on the customer side of the meter)	Count toward meeting utility RPS requirements
Cumulative installations are limited by CPUC Rule 21 to 15% of the peak load on a distribution feeder, before a "Supplemental Review" must be performed and additional protections or upgrades may be required.	Installations are not limited by Rule 21, but an interconnection study is required that may identify needed transmission system upgrades
May help to defer or avoid transmission and distribution system upgrades	May add to the need for transmission and distribution system upgrades
Do not incur real power losses on the transmission and distribution system	Incur real power losses on the transmission and distribution system
Generally have lower quality insolation due to location in urban areas (e.g., smog, increased likelihood of shading, increased cloud cover due to proximity to the coastline)	Can be located in areas with high quality insolation (e.g., Mojave Desert).

Q. Does Mr. Powers testimony address whether UPV installations are a viable alternative to ISEGS?

A. No, Mr. Powers' testimony is focused exclusively on the FSA's "inadequate analysis of the distributed photovoltaic alternative" (Powers, p. 1). The FSA considered four alternative solar technologies to the ISEGS solar tower technology at the ISEGS site, including utility-scale solar PV technology, and concluded that "these technologies would not substantially reduce visual impacts or biological resources impacts." (FSA, p. 4-82). However, Mr. Powers' testimony does not address the FSA's findings with respect to these alternative solar technologies at the ISEGS site.

Q. Since Mr. Powers' criticism of the FSA relates only to its analysis of the DPV alternative, is he consistent in confining his testimony regarding the benefits of PV to only installations that are truly distributed?

A. No, he is not. Mr. Powers repeatedly conflates DPV and UPV installations, citing the benefits of DPV installations while referring to resource potential, cost estimates, and project examples from UPV installations. For example:

- On pp. 2-4, Mr. Powers cites policy support for rooftop and building-integrated DPV applications.
- On p. 4, Mr. Powers discusses "the ability of the solar industry to carry-out multiple distributed PV projects simultaneously, in the range of 400 to 500 MW each" (400-500 MW projects are UPV).
- On pp. 4-5, Mr. Powers discusses the low cost of the Sempra 10 MW project in Boulder City, Nevada, which is a UPV facility located hundreds of miles from the service area of PG&E, the purchaser of the energy.
- On p. 5, Mr. Powers cites SCE's contract with NRG for a 21 MW UPV project in Blythe, California, some 200 miles east of Los Angeles.
- On pp. 11-12, Mr. Powers cites engineering cost estimates for UPV plants in the range of 20-150 MW.
- On p. 12, Mr. Powers cites resource potential estimates from RETI for 20 MW UPV installations in remote locations.
- On p. 13, Mr. Powers cites the transmission and distribution benefits of DPV.
- On p. 15, Mr. Powers cites the transmission and distribution losses benefits of DPV.

Q. How does Mr. Powers' conflation of DPV and UPV installations affect his testimony?

A. This conflation allows Mr. Powers to claim all of the T&D-related advantages of DPV installations, while citing the insolation, costs, and development potential for UPV installations. In reality, very few rooftop PV projects have been announced, while the vast majority of the proposed PV projects are utility-scale projects proposed for similar sites to ISEGS with many of the same environmental and grid impacts.

Q. Mr. Powers states that the CPUC 33% RPS Implementation Analysis 33% Reference Case includes 3,235 MW of distributed PV. Is this an accurate statement?

A. No, the PV projects included in that case are all central station installations based on bids submitted through IOU renewables solicitations.

Q. Mr. Powers states that the CPUC 33% RPS Implementation Analysis High DG case includes 15,000 MW of distributed PV. Is this an accurate statement?

A. No, only 6,000 MW in that case are DPV according to the above definition. The remaining 9,000 MW are remote installations. While these 9,000 MW are labeled "Remote DG" in the report, they are 20 MW projects located remote from load that are assumed to require transmission upgrades. These projects are therefore more properly thought of as UPV in the context of Mr. Powers' testimony, since they do not have the T&D benefits that Mr. Powers cites for DPV projects.

Q. Is there any other central station generation in the CPUC 33% RPS Implementation Analysis High DG case?

A. Yes, the High DG case includes 7,785 MW of new wind, 1,473 MW of geothermal, 490 MW of biomass, and 1,620 MW of solar thermal, in addition to the 9,000 MW of remote PV. Even under the highest projections of DPV considered by the CPUC, over 10,000 MW of incremental central station renewables (in addition to the 9,000 MW of remote PV) are required to meet the 33% RPS goal.

Q. Mr. Powers states that rooftop PV is at the top of the EAP loading order (p. 1). Do you agree that the EAP and subsequent policy documents from the CPUC and CEC express a policy preference for distributed PV over other forms of renewable energy?

A. No, the EAP and subsequent policy documents from the CPUC and CEC do not place DPV in the same category as energy efficiency, nor do they express a policy preference for distributed PV over other forms of renewable energy, including central station solar thermal. To cite one example, the action item "Implement a cost-effective program to achieve the 3,000 MW goal of the Governor's 'Million Solar Roofs' initiative" is listed as Key Action #8 under the "Renewables" category in the 2005 Energy Action Plan II. (EAP II, p. 6) The 2009 Integrated Energy Policy Report does refer to DPV in the context of zero net-energy buildings; however, the CPUC's Zero Net-Energy Building goals apply only to new construction and not to the retrofits of PV onto existing rooftops that are referenced in Mr. Powers' testimony. (CPUC 2008 Annual Report, ftp://ftp.cpuc.ca.gov/OGA/reports/CPUC%202008%20Annual%20Report%20Jan%2030,%202009.pdf p. 22) [Exhibit 72].

3. The DPV technical potential is unknown but likely limited

Q. Mr. Powers cites various estimates of the DPV potential in California: 60,000 MW (Navigant for CEC, 2007); 37,000 MW (Navigant for Energy Foundation, 2004); 27,500 (Black & Veatch for RETI, 2008); 8,000 MW (Black & Veatch and E3 for CPUC, 2009). Based on Mr. Powers' figures, can the Commission be certain that there is sufficient DPV potential to displace all central station renewables for meeting 33% RPS by 2020?

A. No. There is too much uncertainty. Navigant's estimates do not account for shading and, more significantly, assume all rooftops participate. Black & Veatch's RETI estimates are for remote sites that have none of the benefits of DPV. There is no reliable count at this time of the potential MW that could be installed at locations where there would be significant T&D benefits.

Q. What is Rule 21?

A. Rule 21 is a CPUC rule that specifies standard interconnection, operating, and metering requirements for distributed generators (http://www.cpuc.ca.gov/PUC/energy/DistGen/rule21.htm). Rule 21 limits the aggregate quantity of distributed generation that can be located on a given distribution feeder to 15% of the peak load on that feeder, before a "Supplemental Review" must be performed for each interconnection request and additional upgrades or protections potentially required to ensure that the facility would not have a negative impact on utility operations.

Q. Mr. Powers discusses the potential costs of facility upgrades that would be required to connect DG totaling more than 15% of the peak feeder load. Are these figures based on analyses of the cost of modifying distribution facilities to accommodate "upward" power flows, i.e., power flows up through distribution substations onto the transmission system?

A. No, they appear to be generic numbers regarding the cost of new substations. The actual cost of making the necessary upgrades to distribution, sub-transmission and transmission facilities to accommodate thousands of megawatts of DPV projects throughout California is highly uncertain and could be substantially different from the estimates provided by Mr. Powers.

Q. Do distribution-connected PV projects that feed power back up into the grid have the same T&D benefits as DPV projects that serve load downstream on a radially configured distribution feeder?

A. No, they do not. PV projects that feed power back up into the main grid do not avoid distribution system losses and have no ability to defer distribution system upgrades.

Q. Mr. Powers asserts that "approximately 20,000 MW of distributed PV interconnection capacity is available now in California that would require little or no substation upgrading to accommodate the PV." (pp. 7-8) Is this claim accurate?

A. No, it is not. There are several problems with Mr. Powers' assertions:

1. The figures cited are based on distribution system feeder loadings and do not include any estimates of the availability of suitable sites to install PV.

2. The figures assume that no upgrades are required to accommodate DPV up to 30% of peak feeder loading. While the CPUC made this assumption for the purpose of estimating DPV potential for its 33% RPS Analysis, this assumption did not undergo any rigorous technical analysis and was contested by the investor-owned utilities (IOUs) in their comments on the CPUC analysis.

3. The figures assume that all DPV would be located on the utility side of the meter and would therefore count toward RPS compliance. In reality, some of the DPV would

likely be connected on the customer side of the meter in order to take advantage of Net Energy Metering. Net-metered facilities are not RPS-eligible, and would therefore have no impact on the quantity of energy the IOUs must procure from RPS-eligible resources.

Q. What would be a more reasonable estimate?

A. The analysis that E3 and B&V conducted for the CPUC assessed the availability of suitable sites to install PV on each IOU distribution feeder, subject to a limit of 30% of the peak feeder loading. That analysis estimated 6,000 MW of DPV potential using a relatively aggressive assumption that two-thirds of identified roof space would be utilized. However, even that number is contested by the IOUs as too aggressive. For example, PG&E submitted the following comments on the DG potential assumptions:

"The estimates for roof-top capacity appear to be very aggressive. Deployment of these volumes by 2020 will require significant changes to current manufacturing, installation, land use, permitting and electric distribution engineering practices. Also, the source of the data (analysis of available roof space based on satellite photos) does not take into account many roof constraints. This includes structural integrity, since many roofs are not designed to hold the weight and would need to be reinforced. This will likely limit the deployment potential. Further, the usable space may be below the 65% threshold the study assumed due to required access space for firefighting, equipment access, need for space around other roof structures (such as air conditioning units, ventilation, etc.) and layout of the panels themselves." ("Pacific Gas and Electric Company's Comments on the Energy Division's 33% RPS Implementation Analysis Preliminary Results." August 28, 2009. Page 6) [Exhibit 75].

SCE's comments are similar:

"The estimates are high and overstate the practical and economic potential for DG deployment in 2020. The assumption that up to 30% of a distribution circuit's or substation's peak load can "easily" be accommodated by a utility's system is double currently accepted engineering guidelines for "easy" or fast-track interconnections - that is interconnections that do not require more than cursory reviews. The assumptions may be improved with a better definition of "easy," but if this is done, engineering and equipment costs are likely to increase significantly, reducing the potential adoption rate for "Distributed" PV." (Southern California Edison Company's (U 338-E) Comments on, and responses to technical questions regarding, The Energy Division's 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results. Pages 13 and 14) [Exhibit 78].

Q. Does this mean there are only 6,000 MW of PV potential in California?

A. No, there are many thousands and likely hundreds of thousands of MW of potential PV sites in California. However, the vast majority of the sites are not located in places where the T&D benefits of distributed generation are likely to be significant. Rather, they are located in remote areas far from load centers where they would be subject to siting and environmental constraints, would be required to submit interconnection requests to the California ISO, would impose additional flows on the transmission system, and would incur transmission and distribution system losses. In short, these would be UPV projects in similar locations to ISEGS.

Q. Does Mr. Powers present any evidence that it would be technically feasible to interconnect 37,000 MW of DPV resources while maintaining reliable grid operations?

A. No, Mr. Powers presents no evidence regarding the technical feasibility of interconnecting large quantities of PV resources, whether distributed or utility-scale. Among other issues, PV projects are subject to rapid output fluctuations due to changes in cloud cover, and high levels of penetration may result in overgeneration conditions during some hours. It is unknown at this time how much PV can reliably be connected to the grid.

Q. Absent additional central station generation, could DPV meet California's 33% RPS goals by 2020?

A. No. Assuming an 18% capacity factor (DC), approximately 37,000 MW of DPV would be required to fill a resource gap of 59 TWh, and 48,000 MW of DPV would be required to fill a resource gap of 75 TWh. Both estimates far exceed the E3/B&V estimate of 6,000 MW. In addition, it is not known whether it is technically feasible to interconnect such large quantities of distributed PV.

4. Mr. Powers provides no credible evidence to support his claims regarding the low cost of DPV installations

Q. Mr. Powers asserts that the FSA relies on "obsolete" data regarding the cost of DPV installations (p. 11). Does Mr. Powers provide any credible evidence that the numbers cited are indeed obsolete and are "nearly double the actual PV cost in 2009"?

A. No, he does not. The SCE number cited is a target is not the result of actual installations. The RETI thin-film sensitivity case values are engineering estimates and are not the result of actual installations. Mr. Powers provides no evidence of the costs of any actual PV projects to support his assertions.

Q. What are the most recent costs of actual PV projects?

A. The most recent comprehensive public data on the installed cost of distributed PV systems in the United States is a report released in October, 2009 by Lawrence Berkeley National Laboratory ("Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008" Wiser, R., G. Barbose, C. Peterman, and N. Darghouth. LBNL-2674E. October 2009) [Exhibit 80]. The data were obtained from 27 solar incentive programs across 16 states; the primary samples includes about 52,000 grid-connected PV systems installed from 1998 - 2008, totaling 566 MW. The capacity-weighted average cost in 2008 was $7.50/WDC. While this value represents a 4.6% reduction from 2007 a 31% reduction from 1998, it is substantially higher than the $2.70/WAC - $3.50/ WDC that Mr. Powers quotes. Figure ALT-1 shows the installed cost of grid-connected PV systems in the United States between 1998 and 2008 (Tracking the Sun II, p. 10) [Ex. 80].

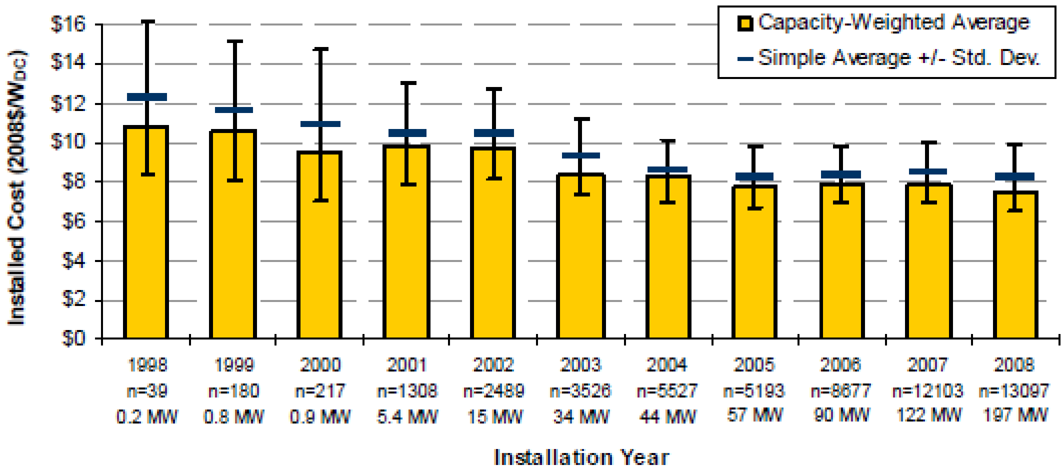

Figure ALT-1: Installed Cost of Grid-Connected PV Systems in the United States, 1998-2008 ("Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008" Wiser, R., G. Barbose, C. Peterman, and N. Darghouth. LBNL-2674E. October 2009) [Ex. 80].

Q. Haven't PV prices come down in 2009?

A. There is anecdotal evidence that PV prices have dropped significantly in 2009. However, there is as of yet very little public data that shows the effect of reduced panel prices on the cost of actual PV systems. Mr. Powers' testimony cites only planning or engineering estimates and does not reference a single actual PV project. Moreover, there is substantial uncertainty about whether this trend stems from a temporary oversupply resulting from the global recession or a more lasting change in the industry's cost structure.

Q. Does Mr. Powers provide any evidence to support his assertion that rooftop projects are less costly than ground-mounted projects?

A. No. Neither the SCE nor the LADWP documents he cites include comprehensive comparisons of the cost of rooftop versus ground-mounted installations; therefore, no conclusion can be drawn. The CPUC 33% RPS Implementation Analysis applied a cost premium of 21% to PV mounted on small rooftops, and 8% on large rooftops, relative to ground-mounted, utility-scale PV.

Q. Based on the E3 Calculator for energy efficiency avoided costs, Mr. Powers' testimony claims that DPV may yield avoided T&D costs of 2.3 to 5.8 cents/kWh. Is this claim accurate?

A. These values are at the high end of the reasonable range. The analysis that Mr. Powers cites actually includes a range of T&D avoided costs from 0.6 to 5.8 cents/kWh (CPUC Rulemaking R.06-02-012, Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent, p. 15).[Exhibit 70] The CPUC 33% RPS Implementation Analysis assumed a range of 1.6 to 2.3 cents/kWh. It should be noted that the real T&D avoided costs may be very site-specific. DPV installations located in a fast-growing area may save more than

2.3 cents/kWh, while DPV installations located in areas that are not growing may not defer any T&D investments.

Q. Mr. Powers' testimony claims that the "slight Reduction in output from Distributed PV is offset by transmission losses from ISEGS" (p. 15). Is this claim accurate?

A. No, it is not. According to the CEC's 2007 IEPR load forecast, average losses from the generator to the load in California are approximately 7.25% (2020 retail sales forecast of 320 TWh relative to "Net Energy to Load" forecast of 345 TWh). These values include both transmission and distribution system losses. However, the difference in insolation between locations is much higher. Table ALT-1 shows some representative capacity factors for various location in California, calculated using the National Renewable Energy Laboratory's "PV Watts" Version 1 web application (http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/). The table also shows the percent change in the capacity factor relative to Daggett, which is the best location modeled in PV Watts. The difference between Daggett and locations close to load centers can be as high as 16% even in sunny locations such as Sacramento. The difference is larger when including less favorable locations such as Arcata. Moreover, these figures are for fixed-tilt systems only. It is possible to install tracking systems for UPV installations that would substantially increase the capacity factor. It is impractical to install tracking systems in DPV installations.

The following standardized assumptions were used for the PV system for each location:

- Size (kW dc): 1,000 kW dc
- DC-AC derate factor: 80%
- Array type: Fixed tilt
- Array tilt: 20 degrees
- Array azimuth: 180 degrees (default – directly south-facing)

	DC Capacity Factor	**Reduction Relative to Daggett**
San Diego	17.51%	-11.52%
Long Beach	16.97%	-14.27%
Los Angeles	17.21%	-13.05%
Daggett	19.80%	—
Santa Maria	18.33%	-7.41%
Bakersfield	17.29%	-12.66%
Fresno	17.20%	-13.11%
San Francisco	16.91%	-14.59%
Sacramento	16.55%	-16.41%
Arcata	14.02%	-29.19%

Table ALT-1: Capacity factor of a standardized PV installation at a variety of locations in California. The chart shows that PV installations located near load centers in Los Angeles, San Francisco and Sacramento would see output reduced by 13-16% relative to a more optimal location such as Daggett.

Q. Do transmission and distribution system losses matter for RPS compliance?

A. No. California's RPS statute requires utilities to serve 20% of their retail sales with qualifying renewable resources. No deduction for losses is applied to remote resources, nor is any additional credit granted to distributed resources. Thus, for the purpose of RPS compliance, there is no advantage to pursuing DPV over UPV installations.

Q. What would be the effect on the levelized cost of energy from a DPV facility if current federal tax incentives were removed?

A. The federal government currently grants a 30% Investment Tax Credit (ITC) and accelerated depreciation according to a five-year Modified Accelerated Cost Recovery System (MACRS). However, the ITC is scheduled to revert from 30% to 10% in 2016. Table ALT-2 shows the effect on the LCOE of PV solar resources if the ITC were reduced from 30% to 10% and the MACRS schedule extended to from 5 to 20 years. Reducing the ITC to 10% increases the cost of PV plants dramatically, and extending the depreciation period from 5 to 20 years results in another large increase in the $/MWh cost of PV. This indicates that the viability of DPV as a strategy for meeting California's renewable energy goals is strongly dependent on the willingness of the federal government to continue granting such generous tax incentives.

	With Current Incentives	**With 10% ITC**	**With 10% ITC and 20-year MACRS**
Reference Case: $7.05/ W_{AC}$	$305.98	$413.67	$513.42
Low-Solar Cost Sensitivity: $3.70/ W_{AC}$	$168.21	$227.05	$281.55

Table ALT-2: Levelized Cost of Energy from 33% RPS Calculator Under Current Federal Tax Incentives (30% ITC and depreciation according to 5-year MACRS), with the ITC reduced to 10%, and with the ITC reduced to 10% and depreciation according to 20-year MACRS.

Q. Based on Mr. Powers' testimony, can the Commission conclude that the cost of a DPV-only strategy is similar to or lower than the cost of a strategy that includes central station renewables?

A. No, it cannot. While the possibility of DPV projects installed at $3/W_{DC}$ is exciting, there is no reliable evidence at this time that DPV projects can be installed at a large scale at these costs. The most recent factual evidence about the cost of actual DPV installations is shows substantially higher costs than the estimates Mr. Powers provides. Moreover, the PV industry is heavily dependent on the continuation of federal tax incentives. Finally, Mr. Powers' testimony focuses only on the direct costs of PV installations, and entirely ignores indirect costs such as integration costs and capacity costs that would likely be increased under a DPV-only strategy relative to a more diversified strategy. In the absence of convincing evidence to the contrary, the Commission can only conclude that central station renewable generation, whether from PV, solar thermal, wind, geothermal or bio-energy sources, continues to provide important cost advantages relative to distributed PV generation at this time.

Q. Does this conclude your testimony?

A. Yes it does.

C2. The following testimony is offered by Roger Gray

System Planning and Operating

Q. What is your name and address?

A. My name is Roger Gray. I am owner of Great Northern Exchange, LLC (GNEX) consulting. My address is 630 Banister Lane, Alamo, CA 94507

Q. What is the purpose of your testimony?

A. I was retained by BrightSource Energy to respond to the testimony of Mr. Bill Powers alleging that the Final Staff Assessment (FSA) improperly concludes that distributed photovoltaic solar power is not a viable alternative to the Ivanpah Solar Electric Generating Station (ISEGS).

Q. What are your qualifications and experience?

A. My resume was previously submitted in this proceeding on November 16, 2009. In summary, I have more than 25 years of work experience in the electric utility industry. The most relevant portions of my work experience with respect to this subject were my positions at Pacific Gas & Electric Company (PG&E) of: (1) Director of Electric Resources Planning and (2) Director of Electric Systems Operation ("Power Control").

Q: Is Mr. Powers assertion that distributed PV is a viable direct replacement for all central station power plants correct?

A: No, it is not. While I have no issue with Mr. Powers' assertion that distributed PV is a viable technology I do not believe that distributed PV can be viewed as simply as Mr. Powers suggests. Distributed PV behaves very differently than central-station solar generation, would have substantially different impacts on the electrical system than central-station solar generation, and cannot be considered a one-for-one substitution of central station solar generation like ISEGS.

Furthermore, from a planning and operating perspective, no utility should endanger reliability and customer costs by putting all its eggs in one basket, whether that basket is central station solar, wind, nuclear gas, coal, conservation or distributed PV. As the penetration of variable (or "intermittent") resources increases in the electrical system, reliability can only be maintained either through multiple renewable technologies in multiple geographic locations reinforcing each other, or through conventional peaker plants, often located in low income areas where environmental justice is a concern. It is not viable from a planning or operating perspective to meet RPS goals of 20 to 33% by relying on a single technology. It is not a matter of ISEGS "or" distributed PV. For California to meet its goals, it must rely on central station solar power *and* distributed PV *and* many other resources.

Q: Does distributed PV provide the same benefits as conservation programs?

A: No, it does not. One of the problems with relying solely on distributed PV is that it is not the same as conservation. Well crafted conservation programs eliminate or reduce electric demand (KW) or consumption (KWh). Distributed PV "masks" that electric demand or consumption when it is operating, but the underlying demand is still there. That underlying demand still needs to be served if the distributed PV output goes away, even for a few moments. One issue with distributed PV output is that its output is very volatile due to cloud cover or overcast. When located in coastal areas, where much of our population and rooftops are located, the variable weather will cause high variation in DPV output.

Q: Does this volatility impact how a transmission or distribution system operator operates its system?

A: Yes it does. Unlike central-station solar power, distributed PV is neither dispatchable nor does it have a scheduling coordinator communicating with the grid operator. Central station solar thermal resources such as ISEGS are, of course, subject to solar variation, but the thermal nature of ISEGS makes ISEGS a partially dispatchable resource with less volatile output than distributed PV. ISEGS and other central-station solar power will have scheduling coordinators required to forecast their operation, including weather impacts, so that the grid operator is constantly informed of what the central-station solar power plant will be doing and why, so the grid operator can react appropriately. Central station plants (solar or otherwise) are designed to be able to move power across the grid through the integrated transmission system. Distributed generation, including distributed PV, is much more localized interconnected at lower voltages, and without major changes in the distribution and transmission systems would have very limited transmissibility.

There will be times when the load on a distribution circuit may range from very light to very heavy loading all within an hour. Depending on the amount of distributed generation power flow direction may actually change direction. For example, on hot days when heat has built up into buildings there will be large air conditioning driven loads. Distributed PV output will vary both by time of day and cloud cover- again, much more so than central-station solar in desert areas with lesser weather impacts. Within a given hour typical AC driven loads are not nearly as volatile due to the thermal mass. However, distributed PV output can and does vary substantially. This is why modern distribution circuits designed to handle growing amounts of distributed PV (or other distributed generation) may need to be "two-way" rather than "one-way" circuits.

With today's system of small amounts of distributed generation, the main transmission and distribution system concerns are safety (e.g. backfeed of power). When intermittent resources such as distributed PV are an extremely small portion of the resource mix the challenges are manageable. However, as distributed generation grows energy management challenges dramatically increase from a planning and operating standpoint.

As penetration of distributed PV increases, utility operators will be required to carry increased levels of operating reserves in the form of very quick response generation that is typically either hydro-electric or gas-fired turbines. This is because the underlying demand must still be served when distributed PV resources turn off due to clouds, or fails for any other reason. In addition to seasonal and daily fluctuation of solar output, minute-to-minute output variations are also an important consideration to a system operator. When distributed PV output is suddenly reduced, other resources will have to respond instantaneously to serve the underlying demand; when the distributed PV output suddenly resumes, the resources that have already responded will have to be adjusted downward to avoid the dangerous conditions that result from too much power being injected into the system. These adjustments are both costly to ratepayers and cause resources to operate inefficiently, increasing emissions (both greenhouse gas and other air pollutants). Central-station solar power, by contrast, would be informing the grid operator of forecasted weather conditions and the power plant's planned response, including informing the grid operator of when the plant will be returning to full output. The grid operator would not have the same surprise with central station solar power, either when output is reduced or when output resumes, than it would with distributed PV. Additionally, solar-thermal generation output is not as volatile due to thermal mass, possible storage and/or supplemental gas firing.

Commitment of dispatchable and flexible resources to back up volatile or intermittent resources such as distributed PV may therefore actually crowd out the ability to bring on additional renewable resources to provide highly reliable, readily available reserve power, particularly if utilities rely on a single technology or single resource regions. Diversity in both technologies and resource regions is important from a reliability perspective for system stability, allowing the grid operator to balance variability across the system instead of having to commit conventional peakers.

Q: Can a utility operate a transmission and power system effectively with only distributed PV as a generation resource?

A: No, it cannot. From a planning and operating perspective it is necessary for utilities to incorporate both types of resources (distributed and central) because they are not direct substitutes for each other. Distributed PV behaves like a negative load since it masks load from the transmission and distribution system. However, as I described previously, the load will still be there, whether or to what extent the distributed PV continues to provide power. In contrast, a 400 MW central station plant provides the transmission system operator with flexibility to move the power to where it is needed on an integrated utility system. Distributed PV cannot provide this system flexibility.

Central station plants including solar thermal plants are necessary for reliable system operation because they contribute both real power (in MWH), but also help by providing other important utility requirements such as reactive power, voltage and frequency support, reserves and other such requirements.

Q: What is your understanding of PG&E's concerns with the CAISO's integration study with respect to DG?

A: PG&E stated: "PG&E would like to express concern that the CAISO's integration study will not sufficiently address the integration requirements of higher RPS goals. Based on its most recent draft scope, the study: (1) does not capture hour-ahead and day-ahead forecast errors of intermittent resources, and (2) does not address the adequacy of the existing planning reserve requirement."2

Q: What is your understanding of PG&E's opinion of the estimates of DG potential in the 33% Implementation Analysis Preliminary Results?

A: PG&E stated that it has concerns about the reasonableness of Black & Veatch's estimates and about the validity of the High DG case as a whole. PG&E thinks that the cited roof-top capacity is very aggressive, citing a few primary reasons: (1) structural integrity of available roofs, (2) roof access, (3) and willingness of building owners. PG&E also states that significant distribution and possible transmission-level upgrades are necessary to meet their estimates for ground-mounted distributed PV, as well as challenges associated with land availability (biological impact, Williamson Act land availability, flood plain constraints, land costs, etc.). PG&E states:

"The estimates for roof-top capacity appear to be very aggressive. Deployment of these volumes by 2020 will require significant changes to current manufacturing, installation, land use, permitting and electric distribution engineering practices. Also, the source of the data (analysis of available roof space based on satellite photos) does not take into account many roof constraints. This includes structural integrity, since many roofs are not designed to hold the weight and would need to be reinforced. This will likely limit the deployment potential. Further, the usable space may be below the 65% threshold the study assumed due to required access space for firefighting, equipment access, need for space around other roof structures (such as air conditioning units, ventilation, etc.) and layout of the panels themselves. The study also assumes that 1/3 of the owners are willing, but their willingness will likely be tied to the financial remuneration they will receive for using their roof space. Many current offerings have been below the expectation of the building owners. This will affect the economics of the projects themselves. The study does not appear to take into account insolation, and how many of these buildings are in prime solar resource areas, again affecting economics. Finally, the assumption on how much of a location's peak load can be met by an intermittent resource may be aggressive, especially given that peak load is later in the day than peak PV output.

By comparison ground mount PV installation estimates are more plausible but still aggressive. First, the largest volume of ground-mounted units exceeds the studies threshold of 30% of peak load at the point of interconnection. This will likely mean significant distribution and possible transmission-level upgrades are required. Further, the study says nothing of the ability to maintain grid stability at these higher generation levels, especially at the local level where power quality may be significantly affected. The "easy" interconnection potential of 2,266 MW may be accurate, but the interconnection costs will need to be better understood. Further, available land for these sites may prevent actual execution. Land issues associated with this type of installation are: biological impact, excessive mitigation requirements, permitting delays, Williamson Act land availability, flood plain constraints, and land costs which can vary in price from $5,000 to $10,000 per acre.

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2 "Pacific Gas and Electric Company's Comments on the Energy Division's 33% RPS Implementation Analysis Preliminary Results." August 28, 2009. Page 6 [Ex. 75]

Overall, the implementation analysis makes a solid attempt at identifying a plausible figure for DG potential. However, as enumerated above, PG&E has significant concerns about the reasonableness of Black & Veatch's estimates and therefore about the validity of the High DG case as a whole. Such uncertainty reinforces the importance of utilizing the 33% implementation study as an analytical framework for policy planning and not as a prescriptive resource plan that will influence the commercial procurement process."[3]

Q: What operational issues did PG&E raise that would result from 15,000 MW of in-state solar PV resources (in relation to the 33% RPS Implementation Analysis)?

A: PG&E stated that it thinks that 15,000 MW of in-state PV resources would require significant investment in local voltage support, upgrades of local distribution networks, back-up generation, and potentially local energy storage. [4]

Q: What is your understanding of SCE's opinion of the estimates of DG potential in the 33% Implementation Analysis Preliminary Results?

A: SCE stated that it does not think that these estimates are plausible or a reasonable source of information for the study, citing a few main issues: (1) SCE's distribution systems are not designed to accommodate large concentrations of distributed generation, (2) load reductions outside of the LA load basin may, and probably will, also require transmission facilities to be built to accommodate the change in load flows from existing generation, and (3) engineering and equipment costs are likely to increase significantly if interconnections do not require more than cursory reviews, reducing the potential adoption rate for distributed PV. SCE states:

"The estimates are high and overstate the practical and economic potential for DG deployment in 2020. The assumption that up to 30% of a distribution circuit's or substation's peak load can "easily" be accommodated by a utility's system is double currently accepted engineering guidelines for "easy" or fast-track interconnections - that is interconnections that do not require more than cursory reviews. The assumptions may be improved with a better definition of "easy," but if this is done, engineering and equipment costs are likely to increase significantly, reducing the potential adoption rate for "Distributed" PV. SCE also takes issue with defining PV or other technologies as DG simply because the generation is connected to the distribution grid. This is especially true in areas outside of the Los Angeles load basin where reducing the load on local systems will tend to increase the amount transmission capacity needed to send other generation to remote load centers.

There are three flaws with the Study's DG potential assumptions that render those assumptions unreliable:

- SCE's distribution systems are not designed to accommodate large concentrations of distributed generation. The overcurrent protection and voltage schemes and

[3] "Pacific Gas and Electric Company's Comments on the Energy Division's 33% RPS Implementation Analysis Preliminary Results." August 28, 2009. Pages 9 and 10. [Ex. 75]

[4] "Pacific Gas and Electric Company's Comments on the Energy Division's 33% RPS Implementation Analysis Preliminary Results." August 28, 2009. Page 12. [Ex. 75]

equipment will likely need to be revised and/or replaced if the DG potential estimated by B&V and E3 were to be installed.

- The report includes several "disclaimers" that the study did not include an evaluation of the technical feasibility of interconnecting the quantities assumed. Without such evaluations the estimates cannot be said to be "plausible." In addition, there was no economic analysis done to attempt to verify that such project development might actually occur in the current market structure.
- Much of the renewable generation to be connected under the High DG scenario is proposed to be located outside of the LA load basin and is deemed to be "DG" simply because it can be located near an existing distribution substation. Load reductions outside of the LA load basin may, and probably will, also require transmission facilities to be built to accommodate the change in load flows from existing generation."[5]

Q: What operational issues did SCE raise that would result from 15,000 MW of in-state solar PV resources (in relation to the 33% RPS Implementation Analysis)?

A: SCE stated that it sees many operational issues associated with that level of penetration, particularly in regard to the lack of CAISO control for PV and the fact that there are currently no provisions allowing for utility monitoring of such resources. SCE states:

"With respect to operational concerns, it is unclear how, if at all, the lack of CAISO control for PV and other variable resources should be taken into account in the evaluation process. There are currently no provisions allowing for utility monitoring of such resources. While conventional utility resources, including generation operated by independent power producers, are dispatchable and relatively transparent to utility/ISO operators, the current paradigm for distributed renewable resources is based on autonomous and informal operation. Even if the CAISO were provided with additional visibility and control of the thousands of small renewable resources envisioned, there would still need to be a "great fleet" of fast responding generation or energy storage devices available and ready to supplement system capacity requirements. SCE believes it is shortsighted and potentially dangerous to "assume" a scenario that has no operational precedent and may not be feasible."[6]

Q: What is your understanding of SDG&E's opinion of the estimates of DG potential in the 33% Implementation Analysis Preliminary Results?

A: SDG&E stated that it thinks that there is significant uncertainty associated with the DG potential in the analysis and thinks that all the amount of DG is increase that the costs associated will increase. SDG&E states:

"As the report stated these estimates are based on high level screens and rules of thumb. As compared to other assumptions less is known in this area and thus these screens and rules likely have a wider range of uncertainty than many other assumptions in the report.

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[5] Southern California Edison Company's (U 338-E) Comments on, and responses to technical questions regarding, The Energy Division's 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results. Pages 13 and 14. [Ex. 78]

[6] Southern California Edison Company's (U 338-E) Comments on, and responses to technical questions regarding, The Energy Division's 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results. Pages 16 and 17. [Ex. 78]

SDG&E does believe that as the amount of DG is increased that the costs associated with these cases will increase."7

Q: What is your understanding of the barriers or issues with the interconnection of distributed renewable generation raised by Black & Veatch on December 9, 2009, at the Re-DEC Working Group Meeting?

A: B&V cited 21 challenges. 13 near-term challenges, and 8 long-term challenges.8

Q: What did the presentation by Black & Veatch at the Re-DEC Working Group Meeting on December 9, 20099 cite as the "high effort" solutions to barriers or issues with the interconnection of distributed resources?

A: (1) Market: market penetration model for PV does not exist, which impacts utilities and California planning processes. (near-term challenge – slide 23) [Exhibit 71]

(2) Siting: spatial distribution of potential PV installations, especially larger ones, is unknown. (near-term challenge – slide 23) [Ex. 71]

(3) Integration: forecasting solar resource may be necessary to control overall system (long-term challenge – slide 28) [Ex. 71]

(4) Modeling: there is a lack of appropriate weather data, which inhibits analysis of real-world insolation conditions and system response. (long-term challenge – slide 28) [Ex. 71]

(5) Modeling: There is a lack of accepted or vetted equipment models to simulate large amounts of PV generation on the distribution system. (long-term challenge – slide 28) [Ex. 71]

(6) Operational: Each utility has different operating philosophies, loading protocols, etc, which makes it difficult for developers to implement projects across the state. (near-term challenge – slide 29) [Ex. 71]

Q: What is your understanding of the grid integration issues of distributed solar that the High Penetration Solar Deployment Project has identified under the DOE's American Recovery and Reinvestment Act (ARRA)?

A: Power output forecasting, micro-climate effects, voltage regulation, reverse power flow, unintentional islanding, false inverter trips, reactive power control, fault contribution, protection, communications, and intentional islanding operation10

Q: What is your understanding of how the North American Electric Reliability Corporation views distributed variable generators (including distributed PV) as being similar to

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7 "SDG&E Response to Questions on 33% RPS Implementation Analysis Preliminary Results report." Page 4. [Exhibit 76]

8 "Potential Challenges to High Penetration of Distributed Renewable Generation" Re-DEC Working Group Meeting. December 2009. [Exhibit 71]

9 "Potential Challenges to High Penetration of Distributed Renewable Generation" Re-DEC Working Group Meeting. December 2009. [Ex. 71]

10 High Penetration Solar Deployment Projects. http://www1.eere.energy.gov/solar/high_penetration.html [Exhibit 79]

transmission-connected variable generation in terms of impacts on the bulk power system? What grid issues did NERC cite in connection to distributed variable generators?

A: In their April 2009 report, NERC stated that "Distributed variable generators, individually or in aggregate (e.g. small scale photovoltaic), can impact the bulk power system and need to be treated, where appropriate, in a similar manner to transmission connected variable generation." In addition, they cited the following issues: "forecasting, restoration, voltage ride-through, safety, reactive power, observability and controllability" and stated that high levels of distributed generation may require new network design.11

Q: What is your understanding of the NERC task force's recommendations in relation to distributed variable resources?

A: NERC has three primary recommendations:12

1. "NERC Action: Variable distributed resources can have a significant impact on system operation and must be considered and included in power system planning studies. The NERC Planning Committee should review and study the impact of distributed generation on bulk power system reliability, and the possible need to recognize owners and operators of such distributed generation in the NERC registry criteria."
2. "NERC & Industry Action: Existing bulk power system voltage ride-through performance requirements and distribution system anti-islanding voltage drop-out requirements of IEEE Standard 1547 must be reconciled by the NERC Planning Committee and IEEE Power and Energy Society."
3. "Industry Action: Research and development activities to measure the impact on reliability of distributed variable generators should be encouraged and supported."

Q: What is your understanding of how NERC views distributed PV and whether it creates more of an operational challenge than central-station generation?

A: NERC speaks of the need for visibility and control of variable resources, which would be very challenging for distributed PV.

"For variable generation to provide power plant control capabilities, it must be visible to the system operator and able to respond to dispatch instructions during normal and emergency conditions. Real-time… power output, availability, and curtailment information is critical to the accuracy of the variable generation plant output forecast, as well as to the reliable operation of the system. It is critical that the Balancing Area operator have real-time knowledge of the state of the variable generation plant and be able to communicate timely instructions to the plants. In turn, variable generation plant operators need to respond to directives provided by the Balancing Area in a timely

11 "NERC: Accommodating High Levels of Variable Generation." April 2009. http://www.nerc.com/FILES/IVGTF_REPORT_041609.PDF, Page 52. [Exhibit 74]

12 "NERC: Accommodating High Levels of Variable Generation." April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf Page 53. [Ex. 74]

manner. The need for this information was clearly illustrated during the restoration of the UCTE system following the disturbance of Nov. 9, 2006 when there was a lack of communications between distribution system operators (DSOs) and transmission system operators (TSOs) delayed the TSO's ability to restore the bulk power system. Therefore, as small variable generation facilities grow into significant plants contributing significantly to capacity and energy, balancing areas will require sufficient communications for monitoring and sending dispatch instructions to these facilities. Further, Balancing areas and generator owner/operators must ensure procedures, protocols, and communication facilities are in place so dispatch and control instructions can be communicated to the variable generation plant operators in a timely manner."[13]

Q: What is your understanding of NERC's views with respect to the additional challenges associated with the increased penetration of distributed resources?

A: NERC states that there may be a need to enhance distributed system designs to accommodate reactive power control requirements, coordinated system restoration, visibility of and communication with distributed variable resources by bulk power system operators, and system protection and safety concerns.

"Another significant consideration is the influence of high levels of variable generation on the distribution system. As the penetration of distributed resources grows, their influence on bulk system supply and delivery planning, including their variable generation characteristics (e.g. ramping), cannot be ignored. For example, to maintain bulk power system reliability, distribution system designs may need to be enhanced to accommodate reactive power control requirements, coordinated system restoration, visibility of and communication with distributed variable resources by bulk power system operators, as well as system protection and safety concerns. In addition, the NERC Functional Model may need to be enhanced in the future to recognize owners and operators of distributed generation."[14]

Q: What is your understanding of NERC's suggestions regarding the need for additional studies be completed in regard to distributed resources and how they might affect the reliability of the bulk power system?

A: I understand that NERC suggests that a study is needed to reconcile bulk power system voltage ride-through requirements and IEEE Standard 1547 in order to maintain the reliability of the bulk power system (e.g. tripping of local generation during distant faults, tripping of generation during under-frequency load shedding, complications with system restoration).

"In some areas of North America, it is possible that very high penetrations of distribution system connected variable generation could be achieved in the future, as has occurred in some regions of Denmark and Germany. As mentioned earlier, under these circumstances, the requirement for bulk power system voltage ride-through capability can be in conflict with the anti-islanding voltage drop-out requirements of distribution

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[13] "NERC: Accommodating High Levels of Variable Generation." April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf Pages 29 and 30. [Ex. 74]

14 "NERC: Accommodating High Levels of Variable Generation." April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf Page 52 [footnote omitted]. [Ex. 74]

connected generation which comply with IEEE Standard 1547. A study is needed to reconcile bulk power system voltage ride-through requirements and IEEE Standard 1547 in order to maintain the reliability of the bulk power system (e.g. tripping of local generation during distant faults, tripping of generation during under-frequency load shedding, complications with system restoration)."[15]

Q: Is someone studying the impact of distributed variable generation on bulk system reliability?

A: Yes, I understand that NERC concluded that "variable distributed resources can have a significant impact on system operation and must be considered and included in power system planning studies" and has a planning sub-group that is studying the impact of distributed variable generation on bulk system reliability and will make recommendations regarding recognizing owners and operators of distributed generation in the NERC Functional Model. This planning sub-group is scheduled to begin in Q1 2010 and will end in Q2 2011.[16]

Q: Based on all the references cited above from PG&E, SCE, SDG&E, B&V, NERC, etc., what is your overall conclusion about the extent to which distributed PV will be a system planning and operating challenge and whether distributed resources can be easily substituted for central-station resources?

A: My conclusions are in line with those conclusions and statements cited by the various parties listed in the prior Q&A. My conclusions are also consistent with my personal experience planning and operating the PG&E system when I was employed by PG&E. All resource categories bring unique characteristics and challenges. It is not as simple as substituting one kind of resource for another based on MW and similar MWHs of production. Increasing levels of distributed PV will require new engineering approaches to the transmission and distribution system and new methods of planning and operating. In the end, my conclusion remains that utilities must continue to rely on a portfolio of different kinds of resources including central station, distributed resources and conservation. Certainly advances in technology such as the much hyped "smart grid" may ultimately permit more reliable integration of more renewable and intermittent resources (central and distributed), but for the near and moderate term future we will be better served by a diverse portfolio of resources.

Q: Can you offer some analogies to why relying solely on distributed PV would not work from a system planning or operating standpoint?

A: Yes. An analogy to Mr. Powers' viewpoint of "stacking resources" in the loading order might be looking at different wind regions for siting wind turbines. Under Mr. Powers' interpretation of loading order, utilities would be required to pick the best wind region and then put all of their wind turbines there. Although California might theoretically meet its RPS goals in MWH from those turbines, the energy from those turbines typically would all be on or off at once, providing too much power at some times and not enough

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15 "NERC: Accommodating High Levels of Variable Generation." April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf Page 52. [Ex. 74]

16 "NERC: Accommodating High Levels of Variable Generation." April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf Page 71. [Ex. 74]

in others. The lack of diversity would pose a major challenge to system reliability, and would force other resources to operate inefficiently in response. California would be far better off getting wind resources from multiple locations, so that the wind would unexpectedly starting or stopping in one area could be balanced by wind blowing in other areas. In fact, this is a major reason that California's utilities are diversifying their resources broadly among technologies.

Q: Does this conclude your testimony?

A: Yes it does.

Biological Resources

I. Introduction

A. Name: John Cleckler, Mark Cochran, Amy Hiss, Geof Spaulding, Ann Howald, Russ Huddleston, John Carrier, Steve De Young, and Andrew Sanders.

B. Qualifications: The qualifications of the various authors are as noted in their resumes contained in Appendix A of Applicant's Initial Testimony filed on November 16, 2009.

C. **Prior Filings:** In addition to the statements herein, this testimony includes by reference the following documents submitted in this proceeding; these documents are in addition to those previously submitted with Applicant's Initial Testimony:

- CH2M HILL and Garcia and Associates (GANDA). 2009. Draft Ivanpah SEGS Special-Status Plant Avoidance and Protection Plan. January. [Exhibit 81]
- Dixon, J. B. 1937. "The Golden Eagle in San Diego County, California." *Condor.* 39: 49-56. As cited in Digital-Desert.com on the internet at: http://digital-desert.com/wildlife/golden-eagle.html [Exhibit 82]
- Dolan, Brian F. 2006. "Water Developments and Desert Bighorn Sheep: Implications for Conservation." *Wildlife Society Bulletin*. 34 (3) 642-646. Available at: http://www.jstor.org/stable/3784691 [Exhibit 83]
- E-mail from Brian Croft to Susan Sanders, August 18, 2009, Regarding Desert Tortoise Translocation. [Exhibit 73]

D. Documents Entered as Exhibits by Others: The following documents were cited in this testimony, but have been previously entered as exhibits by other parties.

- Richardson and Miller. 1997. "Recommendations for Protecting Raptors from Human Disturbance: A Review." *Wildlife Society Bulletin*. 25(3):634-638 [CBD Exhibit 933]

To the best of our knowledge, all of the facts contained in this testimony (including all referenced documents) are true and correct. To the extent this testimony contains opinions, such opinions are our own. We make these statements, and render these opinions freely and under oath for the purpose of constituting sworn testimony in this proceeding.

II. Summary of Rebuttal Testimony

A. Wildlife

Desert Tortoise

The Applicant does not agree that the impact of the project needs to be further analyzed relative to the Northeastern Mojave recovery unit. In terms of planning for the recovery of the species, the USFWS subdivided the range of the Mojave population of the desert tortoise into six evolutionarily significant units or ESUs (see Figure BIO-1). These ESUs consist of populations or groups of populations that show significant differentiation in genetics, morphology, ecology, or behavior. The ESUs were then identified as Recovery Units ***for purposes of designing a reserve system.*** The reserves are known as Desert Wildlife Management Areas (DWMAs). The Project area is within the Northeastern Mojave Recovery Unit (RU) (see Figure BIO-2), but not within a DWMA. The broadly delineated RU encompasses southern Nevada (all but the southernmost tip), southwest Utah, and the Arizona strip (Arizona north of the Colorado River). The Ivanpah project, on the western edge of this RU, encompasses a very small portion of this Recovery Unit as a whole. Per the GIS, the Northeastern Mojave Recovery Unit is about 9 million acres in size. The DWMAs within that RU comprise about 1,215,000 acres (4,917 km^2).[1] Not only is Ivanpah SEGS is not in a DWMA, it only comprises about 3/10 of one percent (0.003) of the area within the DWMAs. Obviously, it is not a significant portion of this "evolutionarily significant unit." The fact that the range of this ESU (Recovery Unit) extends into a relatively small portion of California (a political boundary) is of no biological significance. Based on the designations of the RUs, tortoises at the Ivanpah SEGS site are similar in terms of genetics, morphology and ecology to expansive areas in Nevada, Utah, and Arizona as noted. Sufficient critical habitat and designated DWMAs in southern Nevada, southwestern Utah, and the Arizona strip provide for the recovery of this ESU (i.e., Northeastern Mojave recovery unit).

Within the Ivanpah Valley, the BLM has designated the Ivanpah DWMA as part of the overall recovery efforts for the species. The Ivanpah DWMA comprises approximately 58 square miles. The Ivanpah DWMA is located well south of the Project site and is separated from the Project site by Interstate-15. Tortoise densities in the Ivanpah Valley DWMA were estimated between 5 and 250 adult tortoises per square mile at the time of the Recovery Plan. At the Project site (6.25 square miles) the 25 desert tortoises estimated to occupy the site represents approximately 4 tortoises per square mile. This is a valid comparison with the Ivanpah DWMA densities given the similarity of estimates based on surveys or extrapolated from permanent study plots in the case of the DWMA estimates.

Although Mr. Connor claims that the "Northeastern Mojave desert tortoises exhibit the greatest genetic differentiation of the five recognized units occurring in California," Interstate-15 has already isolated them from the remainder of the ESU and the Ivanpah Valley (see Figure BIO-2). Based on this current fragmentation, it is uncertain that this isolated set of tortoises would have any effect on the ESU as a whole.

Staff states that "The ISEGS project area provides high quality habitat for this species, with low levels of disturbance and high plant species diversity" (FSA/DEIS at 6.2-29). Based on the vegetation surveys that were conducted (Supplemental Data Response, Set 2I [Exhibit 46]), Ivanpah 3 has relatively high plant species diversity (average species diversity of 0.64 out of 1.0); however, Ivanpah 1 and 2 have lower plant species diversity (average of 0.40 and 0.45, respectively). The proposed translocation/relocation areas to the west of the Ivanpah SEGS sites have higher plant diversity and richness than the Ivanpah SEGS sites themselves (diversity averages ranging from 0.51 to 0.84). The areas where tortoises are proposed to be translocated/relocated may provide higher quality habitat than the project area itself due to the

[1] USFWS. 2009. "Range-Wide Monitoring of the Mojave Population of the Desert Tortoise: 2007 Annual Report," October. Table 8, Available at: http://www.deserttortoise.gov/documents/RPT_2007_Rangewide_DT_Population_Monitoring_AllisonL_102709.pdf

higher levels of plant species diversity. It should also be noted that the project site is not entirely undisturbed. Staff refers to it as "relatively undisturbed" (at 1-17 and 6.2-95) and as noted above "with low levels of disturbance." It should be noted that there are three high voltage transmission lines and a natural gas transmission pipeline (with associated dirt service roads) that traverse the valley on its northern end. About a dozen 8- to 12-foot-wide dirt trails also criss-cross the valley. A second transmision line corridor (containing two transmission lines and a distribution line) also passes through the valley between Ivanpah 1 and 2.

On page 5 of his testimony, Mr. Connor seems confused about the desert tortoise surveys that were performed for the translocation sites. Protocol desert tortoise surveys of the project area were conducted within the active/protocol season (April 9 to June 5, 2007 and May 20 to May 25, 2008). These surveys identified 25 tortoises within the project area and zone of influence. Desert tortoise surveys of the translocation/relocation areas were conducted in July and August, 2009. The translocation/relocation area surveys were done outside of the protocol season. They were not protocol surveys, and were not presented as such. The intent was to determine if relocating the 25 tortoises found during prior surveys to the translocation area would create an over population situation. The species diversity and richness of the perennial shrubs and cacti from the vegetation surveys conducted for the translocation and relocation areas can be used as a proxy for herbaceous annual species diversity and richness. Areas with greater shrub diversity are likely to support more diverse herbaceous annual diversity. In response to these studies, USFWS declared:

> The Ventura Fish and Wildlife Office has reviewed the latest report on desert tortoise surveys and vegetation surveys in the proposed translocation areas that were completed by CH2MHill and Southern Nevada Environmental Inc for the Ivanpah ISEGS project. Based on the information provided, we feel that there is enough information to evaluate the effects of the relocation of desert tortoises immediately west of the project site and the proposed translocation of desert tortoises from the project site to the identified translocation areas. Based on the results of the surveys, it appears that translocation would be most appropriate in sites N1, N2, N3, and N4 because of higher quality habitat and low density resident populations. (Email from Brian Croft to Susan Sanders, August 18, 2009 [Exhibit 73]).

Golden Eagle

There are no potential significant impacts to golden eagles or other special status wildlife that would require additional mitigation measures. Although the location of the eagle nest is unknown, it is assumed that golden eagles nest in the vicinity of the project site. However, the project site boundary is farther than 1,600 meters (about 1 mile) from the mountain ranges that would likely be the location of the nearest golden eagle nest. Richardson and Miller [CBD Exhibit 933], which is cited regarding line of site disturbance, recommends disturbance buffers of 200 to 1,600 meters from golden eagle nests. Furthermore, Richardson and Miller state that buffer zones are useful tools for resource managers to protect raptors during periods of extreme sensitivity. Therefore, the distance from the project's location from the mountain ranges provides a disturbance buffer greater than that recommended by Richardson and Miller that prevents potential impacts to golden eagles and potential nests.

The extent of a golden eagle's home range around a nest site varies depending on the surrounding resources (prey availability and openness the terrain). Although the territory range varies, at least one study put it at 36 square miles in the San Diego area (Dixon 1937, as cited in http://digital-desert.com/wildlife/golden-eagle.html). Although the project would result in the loss of some foraging habitat, given the large size of desert territories, the loss would not be significant enough to result in the loss of a nest site or additional competition for resources with other eagles.

Nelson's Bighorn Sheep

The photos of the desert bighorn sheep provided by Basin and Range Watch are of sheep in the Stateline Wilderness area and in the Mojave National Preserve west of the project site. The question is whether the project would impact the sheep. The factual information regarding bighorn sheep was considered in the FSA/DEIS and the unknowns regarding potential use of the project site for foraging and the area for bighorn movement were acknowledged in the FSA/DEIS (at 6.2-79 to 80). We do not agree with Basin and Range Watch that further expert assessment would yield more information for consideration. The "best available data" was used in the analysis/effects determinations in compliance with CEQA and NEPA. The type of information Mr. Jorgenson asserts would be needed for a site-specific analysis would require a long-term study of the area with a large number of bighorn fitted with radio-telemetry. Even with this level of effort, data on foraging use of the project area and movement through the area is likely to be so low or infrequent as to provide equivocal information in further assessing the potential impacts or informing mitigation efforts. Further, the harassment to the bighorn sheep of capturing and fitting a sufficient number of bighorn with radio-telemetry could well exceed the value of any information gained.

Bighorn sheep have large home ranges that are often defined by the mountain range within which they are associated. Their use of valleys is likely to be infrequent and brief due to the lack of mountainous terrain this species relies on for escape from predators. The bighorn sheep connectivity poster[2] states that only one migrant per generation is needed to maintain minimum gene flow between the populations.

Applicant disagrees with CEC Staff that the project would create a significant adverse impact to the Bighorn Sheep, and hence, asserts that mitigation is unnecessary. However, Applicant has agreed to provide a source of artifical water as suggested by Staff in BIO-19, but which will be done outside the permitting process, and not as a Condition of Certification. There is evidence to suggest that adding water resources may be a valid means of offsetting the effects of climate change, fragmentation, and disease in desert bighorn. Dolan (2006) made the case that in areas were water resources is a limiting factor the addition of guzzlers could have significant benefits for a stressed bighorn population. It is likely that water is a more limiting resource for bighorn in the mountains around the project area than available forage.

Gila Monsters, American Badger, and Insects

No new evidence was presented that the project represents, individually or collectively, significant impacts to these species. More studies or surveys would not change the impact assessment or improve offered mitigation measures. No significant impacts to these species or

[2] http://www.bren.ucsb.edu/research/documents/WestMojave_Poster.pdf

their habitat are anticipated given the wide distribution of each of these species. Unlike the solar site in McCrary's 1986 study [CBD Exhibit 912], Ivanpah SEGS will not be located near an agricultural field or have open water which would attract insects and birds. Therefore, the projected impacts do not warrant additional mitigation.

B. Botany

A list of 18 special status plants was presented in the CNPS testimony. The CNPS testimony stated that rare plant surveys at the Ivanpah SEGS site are inadequate because they did not include field surveys during the late summer/early fall period. None of the 18 species presented in the CNPS Testimony (December 18, 2009) are federally listed, state listed, or BLM sensitive species.

For these 18 species, information on the life form, blooming time, geographic range, and nearest known locations to the Ivanpah SEGS site is presented in Table BIO-1. Also included in Table BIO-1 is an evaluation of: (1) the likelihood of occurrence at the Ivanpah SEGS site, (2) the likelihood of detection during the 2007 and 2008 surveys, and (3) the likelihood of qualifying for protection under CEQA. Information in Table BIO-1 is based on information from the CNPS online Inventory, the Consortium of California Herbaria's online database (Jepson Online Interchange, reviewed December 28, 2009), and from the personal knowledge of Mr. Andrew Sanders and Mr. James Andre.

Based on the information in Table BIO-1, one of the 18 species (revolute spurge [*Chamaesyce revoluta*]) is likely to be found at the Ivanpah SEGS site, and is unlikely to have been detected during the 2007-2008 surveys. Revolute spurge is on CNPS List 4. One additional species (desert tragia [*Tragia ramosa*]) could possibly occur at the Ivanpah SEGS site. It would have been detectable during the 2007 and 2008 surveys, but no individuals of this species were found. Desert tragia is also on CNPS List 4. Of the 16 remaining species, one has no chance of occurring at the Ivanpah SEGS site, six are very unlikely to occur there, and nine are unlikely to occur there.

The protocol-level rare plant surveys that were conducted in 2007 and 2008 at the Ivanpah SEGS site were of the highest professional quality. They meet the recommendations of the agency botanical survey guidelines in place at the time of the surveys to a higher degree than any other botanical surveys conducted on solar projects in California, and for most other botanical surveys conducted on projects of any kind, throughout the state. The Ivanpah SEGS surveys were planned and supervised by professional botanists with many years of experience and excellent familiarity with the flora of the Mojave Desert. Expert botanists James Andre and Andrew Sanders provided onsite training and served as taxonomic experts during the 2008 surveys. The surveys covered the entire project site using 50-foot-wide transects in both 2007 and 2008. Surveys were conducted from March through June in 2007, and in April in 2008. All plants observed, including dead skeletons, were identified, if possible, during 2007 and 2008. The summer annual and rare plant, nine-awned pappus grass (*Enneapogon desvauxii*), was detected in the form of dead skeletons in 182 locations (more than 8,000 individuals) throughout the Ivanpah SEGS site in April 2008, following late summer rains in 2007. The Ivanpah SEGS surveys successfully located and mapped eight species of rare plants previously unknown in the Ivanpah Valley. The rare plant survey report (2008) included mention of a ninth rare plant species (desert portulaca [*Portulaca halimoides*]) that was reported by James Andre to be present on the Ivanpah SEGS site in late summer-early fall of 2007. Had any other rare plant species been reported from the Ivanpah SEGS site by Mr. Andre prior to report completion, these also would have been mentioned in the survey report.

Thus, the Applicant asserts that rare plant surveys of the site are sufficient to provide an assessment of the project's potential impacts as required by CEQA and NEPA.

Sources

Andre, James, Director, University of California Sweeney Granite Mountains Desert Research Station. Personal communications to Andrew Sanders via telephone and email, November and December 2009.

California Native Plant Society. 2009. Inventory of Rare and Endangered Plants in California. Online version. Accessed at: http://www.cnps.web.aplus.net/cgi-bin/inv/inventory.cgi

Garcia and Associates (GANDA). 2008. Attachment BR3-1A, Technical Report: Botanical Resources of the Ivanpah Solar Electric Generating System. Available at: http://www.energy.ca.gov/sitingcases/ivanpah/documents/index.html

Jepson Online Interchange 2009. Consortium of California Herbaria, specimen records, accessed online at: http://ucjeps.berkeley.edu/interchange.html

Sanders, Andrew, Curator, U.C. Riverside Herbarium, personal communications to Ann Howald and Amy Hiss, in person, and via telephone and email, December 2009.

Summary of Ivanpah SEGS Special-status Plant Avoidance and Protection Plan

The California Native Plant Society (CNPS Opening Testimony, p. 5) and others have argued that rare plant avoidance and minimization measures proposed by the applicant are inadequate. In rebuttal, it is important to note that the purpose of the Ivanpah SEGS Special-Status Plant Avoidance and Protection Plan (Plan) is to identify the steps and procedures that will be implemented to avoid rare plant localities and minimize the extent of rare plant impacts to the maximum degree practicable while achieving energy generation objectives. The intent over the long term is to have the Ivanpah SEGS site support healthy, self-sustaining populations of the avoided rare plants with local distributions similar to pre-project conditions. The Draft Plan will be finalized and submitted to the California Energy Commission Compliance Project Manager (CPM) and the Bureau of the Land Management (BLM) no later than 60 days prior to the start of ground-disturbing activities.

The rare plant species addressed in the Plan include:

- Rusby's desert mallow (*Sphaeralcea rusbyi* var. *eremicola*)
- Mojave milkweed (*Asclepias nyctaginifolia*)
- Desert pincushion (*Coryphantha chlorantha*)
- Nine-awned pappus grass (*Enneapogon desvauxii*)
- Parish's club-cholla (*Grusonia parishii*)

Special terms used in the Plan to describe the areas occupied by rare plants on a variety of scales include:

- *Rare Plant Locality* – a location where one or more rare plant individuals were detected and mapped during protocol-level rare plant surveys at the Ivanpah SEGS site in 2007 and 2008.

- *CNDDB Element Occurrence (EO)* – a location with one or more rare plant individual(s) of a given species that is at least 0.25 mile distant from another Element Occurrence(s) of the same species. An Element Occurrence (EO) may be equivalent to a biological population, but this is often not the case. Element Occurrence boundaries are determined and enumerated by the California Natural Diversity Database (CNDDB). Maps showing EO boundaries are not readily available to the public. The number and location of EOs are changed by the CNDDB in response to new information.
- *Rare Plant Avoidance Zone (RPAZ)* – an area within the Ivanpah SEGS project site that contains one or more rare plant localities and/or individuals that have been avoided during construction. The boundaries of the RPAZs will be established after the post-construction baseline survey is completed. The area within the RPAZs will be the subject of success criteria monitoring and evaluations.

Both engineering and biological constraints were considered in developing the elements of the Plan. Engineering constraints include: pre-construction site modifications, facility layout constraints, and operations constraints. Biological constraints include: seasonal limitations on detecting rare plant presence, dispersal of rare plants from avoided localities into new areas, and the lack of basic ecological information for the rare plant species covered by the Plan.

The basic components of the Plan include:

- Initial selection and mapping of rare plant localities that can potentially be avoided in open areas or through minor modifications in project design
- Project layout modifications to accommodate avoided rare plant localities
- Relocation, mapping and fencing of avoided rare plant localities and rare plant individuals prior to commencement of on-the-ground pre-construction or construction activities
- Salvage of rare plants that cannot be avoided, including relocation to the onsite Rare Plant Transplantation Area
- A post-construction baseline survey to verify which rare plant localities and individuals have been avoided and protected from direct impacts during construction
- Removal of construction fencing and demarking of avoided localities (completed concurrently with post-construction baseline survey)
- Establishment of performance standards for actions needed to assure that avoided rare plants are protected as the Plan describes (e.g., marking and protecting avoided rare plant localities prior to ground-disturbing activities, regularly scheduled and periodic maintenance actions that could affect avoided rare plant localities during operations)
- Establishment of biological success criteria to determine whether avoided rare plants survive and grow over the long-term
- Delineation of Rare Plant Avoidance Zones (RPAZs) as the geographic units within which biological success criteria will be applied

- A long-term monitoring program that includes: (1) performance monitoring (pre-construction, construction and post-construction), (2) a post-construction baseline survey of avoided rare plants, and (3) long-term rare plant monitoring
- Dedication to the principles of adaptive management by utilizing monitoring results to inform rare plant management decisions
- Consideration of remedial actions such as onsite translocation in the event that success criteria for rare plant avoidance are not being met

The Ivanpah SEGS Special-Status Plant Avoidance and Protection Plan is attached hereto as Exhibit 81.

TABLE BIO-1
Information on Eighteen Special-status Plants Listed in the Ivanpah SEGS CNPS Testimony dated 18 December 2009.

Scientific Name/ Common Name[a]	CNPS Status[b]	Life Form	Blooming Time[c]	Comments[d]	Potential for Occurrence and Detection at the ISEGS Site[e]
Amaranthus watsonii Watson's amaranth	4.3	Summer annual	August–September	Documented records from widely scattered locations. No documented site records from Clark Mountains, Ivanpah Valley, or vicinity. Skeletons could likely be identified to genus, but not to species.	Unlikely to occur at the ISEGS site. If it were present, probably would not have been detected during the 2007 and 2008 surveys. Unlikely to qualify for protection under CEQA.
Bouteloua eriopoda Black gramma grass	4.2	Perennial grass	May–August (October)	Documented records from within about 5 miles of project site, in the Clark Mountains. Flowers during time of protocol-level surveys, but more commonly during the fall. Vegetative parts can be identified, although dormant grasses are easy to miss.	Unlikely to occur at the ISEGS site. If it were present, it might have been possible to detect it at some level during the 2007 and 2008 surveys. Unlikely to qualify for protection under CEQA.
Bouteloua trifida Red gramma grass	2.3	Perennial grass	May–June (September)	Documented records from within about 5 miles of project site. Flowers during time of protocol-level surveys, but more commonly during the fall. Vegetative parts can be identified, although dormant grasses are easy to miss.	Unlikely to occur at the ISEGS site. If it were present, it might have been possible to detect it at some level during the 2007 and 2008 surveys. Qualifies for protection under CEQA.
Chamaesyce revoluta Revolute spurge	4.3	Summer annual	August–September	Documented records from within about 5 miles of project site, in Clark Mountains, from elevations similar to those of highest parts of project site. James Andre says he has collected this at or near the ISEGS site. Plant has delicate structure, so skeletons not recognizable.	Likely to occur at the ISEGS site. If present, would not have been detectable during the 2007 and 2008 surveys. Unlikely to qualify for protection under CEQA.
Cordylanthus parviflorus Small-flowered bird's-beak	2.3	Summer annual	August–October	No documented records from the Clark Mountains or the Ivanpah Valley; nearest known location is in the Mid Hills (granite), about 25 miles south of the project site. Typically found in the mountains, at elevations 1,500 ft or more; higher than the highest parts of the project site. Skeletons can be identified to species.	Very unlikely to occur at the ISEGS site. If it were present, the skeletons might have been detectable during the 2007 and 2008 surveys. Qualifies for protection under CEQA.
Euphorbia exstipulata var. *exstipulata* Clark Mountain spurge	2.1	Summer annual	September	Documented records from within about 5 miles of project site, in the Clark Mountains, at elevations about 1,300 ft or more; higher than the highest parts of the project site. Plant has delicate structure, so skeletons not recognizable. Distribution in CA poorly known.	Unlikely to occur at the ISEGS site. If it were present, it would not have been detected during the 2007 and 2008 surveys. Qualifies for protection under CEQA.

TABLE BIO-1
Information on Eighteen Special-status Plants Listed in the Ivanpah SEGS CNPS Testimony dated 18 December 2009.

Scientific Name/ Common Name[a]	CNPS Status[b]	Life Form	Blooming Time[c]	Comments[d]	Potential for Occurrence and Detection at the ISEGS Site[e]
Juncus nodosus Knotted rush	2.3	Perennial herb	July–September	Documented record from Clark Mountains, more than 2,000 ft higher than highest parts of project site. It is documented only from streambanks, lake shores, wet meadows, and seeps. None of these habitats are found within the ISEGS project area.	No chance of this occurring at the ISEGS site—habitat is not present.
Muhlenbergia appressa Appressed muhly	2.2	Annual grass	April–May	No documented records from the Clark Mountains or the Ivanpah Valley; nearest known location is in the Mid Hills/Wildhorse area (granite), about 25 miles south of the project site. Plants have been collected during months when 2007 and 2008 surveys conducted; however, main flowering time in desert is likely late summer to fall. Published flowering times may refer to plants from the Channel Islands. Distribution in CA Mojave Desert poorly known.	Very unlikely to occur at the ISEGS site. If it were present, it would likely have been detected in some form, possibly non-flowering, during 2007 and 2008 surveys. Qualifies for protection under CEQA.
Muhlenbergia arsenei Tough muhly	2.3	Perennial grass	August–October	Documented records from the Clark Mountains, within about 5 miles of the project area. Collection locations are at least 1,500 ft higher than the highest points within the project area. Skeletons may be identifiable, but dormant grasses easy to miss. Distribution in CA poorly known.	Unlikely to occur at the ISEGS site. If it were present, it is unlikely to have been detected during 2007 and 2008 surveys. Qualifies for protection under CEQA.
Muhlenbergia fragilis Delicate muhly	2.3	Summer annual	October	One documented record from the Clark Mountains, but site location not clearly described so distance from project site unknown. Elevation of collection site is approx. 1,500 ft. higher than the highest parts of the project area. Skeletons fragile, unlikely to persist or be identifiable.	Unlikely to occur at the ISEGS site. If it were present, it would not have been detected during 2007 and 2008 surveys. Qualifies for protection under CEQA.
Muhlenbergia pauciflora Few-flowered muhly	2.3	Perennial grass	September–October	No documented records from Clark Mountains or the Ivanpah Valley; nearest known location is in the Mid Hills (granite), about 25 miles south of the project area. Found at elevations approx. 2,000 ft higher than the highest points within the project area. Skeletons unlikely to be recognizable. Distribution in CA poorly known.	Very unlikely to occur at the ISEGS site. If it were present, it would not have been detected during the 2007 and 2008 surveys. Qualifies for protection under CEQA.

TABLE BIO-1
Information on Eighteen Special-status Plants Listed in the Ivanpah SEGS CNPS Testimony dated 18 December 2009.

Scientific Name/ Common Name[a]	CNPS Status[b]	Life Form	Blooming Time[c]	Comments[d]	Potential for Occurrence and Detection at the ISEGS Site[e]
Munroa squarrosa False buffalo grass	2.2	Summer annual	October	Documented site location from within 5 miles of the project area, at an elevation about 1,500 ft higher than the highest parts of the project site. Habitat given as pinyon-juniper woodland, a vegetation type not found within the project area. Skeletons are delicate, would not be recognizable. Distribution in CA poorly known.	Unlikely to occur at the ISEGS site. If it were present, it would not have been detected during the 2007 and 2008 surveys. Qualifies for protection under CEQA.
Physalis lobata Lobed ground-cherry	2.3	Perennial herb	September–January	No documented locations from anywhere in the vicinity of Clark Mountains or Ivanpah Valley. Plant can be active in spring as well as fall. Distribution in CA poorly known; first documented record in CA from 1975.	Very unlikely to occur at the ISEGS site. If it were present, the living plants or dead stems would very likely have been detected during the 2007-2008 surveys. Qualifies for protection under CEQA.
Piptatherum micranthum Little-seed rice grass	2.3	Perennial grass	June–September	Documented records from Clark Mountains, about 7 miles west of the project area, at elevations 2,500 ft or more; higher than the highest points within the project area. Habitat is mountain canyons in pinyon-juniper woodland, a type not found at the project site. Blooming season overlaps somewhat with time of protocol-level survey.	Very unlikely to occur at the ISEGS site. If it were present, it might have been detected at some level during the 2007 and 2008 surveys. Qualifies for protection under CEQA.
Sanvitalia abertii Abert's sanvitalia	2.2	Summer annual	August–September	Documented records from Clark Mountains, about 5 miles west of the project area, at elevations approx. 1,500 ft or more; higher than the highest parts of the project site. Skeletons potentially identifiable because plants have distinctive conical receptacle that persists.	Unlikely to occur at the ISEGS site. If it were present, skeletons might have been detected during the 2007 and 2008 surveys. Qualifies for protection under CEQA.
Schkuhria multiflora var. *multiflora* Many-flowered schkuhria	2.3	Summer annual	September	Documented records from Clark Mountains, about 5 miles west of project area, at elevation approx. 1,500 ft or more; higher than the highest parts of the project site. Habitat identified as pinyon-juniper woodland, which is not found at the project site. Skeletons potentially identifiable.	Unlikely to occur at the ISEGS site. If it were present, it might have been detected at some level during the 2007 and 2008 surveys. Qualifies for protection under CEQA.

TABLE BIO-1
Information on Eighteen Special-status Plants Listed in the Ivanpah SEGS CNPS Testimony dated 18 December 2009.

Scientific Name/ Common Name[a]	CNPS Status[b]	Life Form	Blooming Time[c]	Comments[d]	Potential for Occurrence and Detection at the ISEGS Site[e]
Scleropogon brevifolius Burro grass	2.3	Perennial grass	October	Only documented site record in CA is from the New York Mountains, about 15 miles southeast of the project area, at an elevation approx. 1,500 ft higher than the highest points within the project site. Dormant stems could be identifiable if parts of the inflorescence remains. Distribution in CA poorly known.	Very unlikely to occur at the ISEGS site. If it were present, it might have been detected at some level during the 2007 and 2008 surveys. Qualifies for protection under CEQA.
Tragia ramosa Desert tragia	4.3	Perennial vine	April–May	Documented site records from the Clark Mountains, about 3 to 5 miles west of the project site, at elevations higher than those of the project site. Flowering time overlaps the time when protocol-level surveys were conducted in 2007 and 2008. Dead stems are distinctive.	Possible for this to occur at the ISEGS site, but mainly found higher in the mountains. If it were present, it would have been detectable in flower during the 2007 and 2008 surveys. Unlikely to qualify for protection under CEQA.

Notes:

[a] Scientific names from *The Jepson Manual* (Hickman 1993); common names from the CalFlora online database (2009) and other sources.

[b] California Native Plant Society (CNPS) Status Codes:
1A = Plants presumed extinct in California
1B = Plants rare, threatened, or endangered in California and elsewhere
2 = Plants rare, threatened, or endangered in California, but more common elsewhere
3 = Plants about which we need more information – a review list
4 = Plants of limited distribution – a watch list

CNPS Threat Code Extensions:
.1 = Seriously endangered in California.
.2 = Fairly endangered in California.
.3 = Not very endangered in California.
? = Not determined.

[c] Blooming times from the California Native Plant Society's *Inventory of Rare and Endangered Plants of California*, online version (CNPS 2009).

[d] Comments are based on information from the following sources:

- Andre, James, Director, Sweeney Granite Mountains Desert Research Center, U.C. Riverside, specimen records and personal communications with Andrew Sanders via email and telephone, November and December 2009.
- CNPS. 2009. *Inventory of Rare and Endangered Plants of California*, online version, accessed most recently on 29 December 2009.
- Jepson Online Interchange. 2009. Consortium of California Herbarium, specimen records, accessed most recently on 29 December 2009.
- Sanders, Andrew, Curator, U.C. Riverside Herbarium, reviews of specimen records and personal knowledge.

[e] Likelihood of occurrence at the ISEGS site, and likelihood of having been detected at the Ivanpah SEGS site during surveys in 2007 and 2008, based on information from the Comments column of this table.

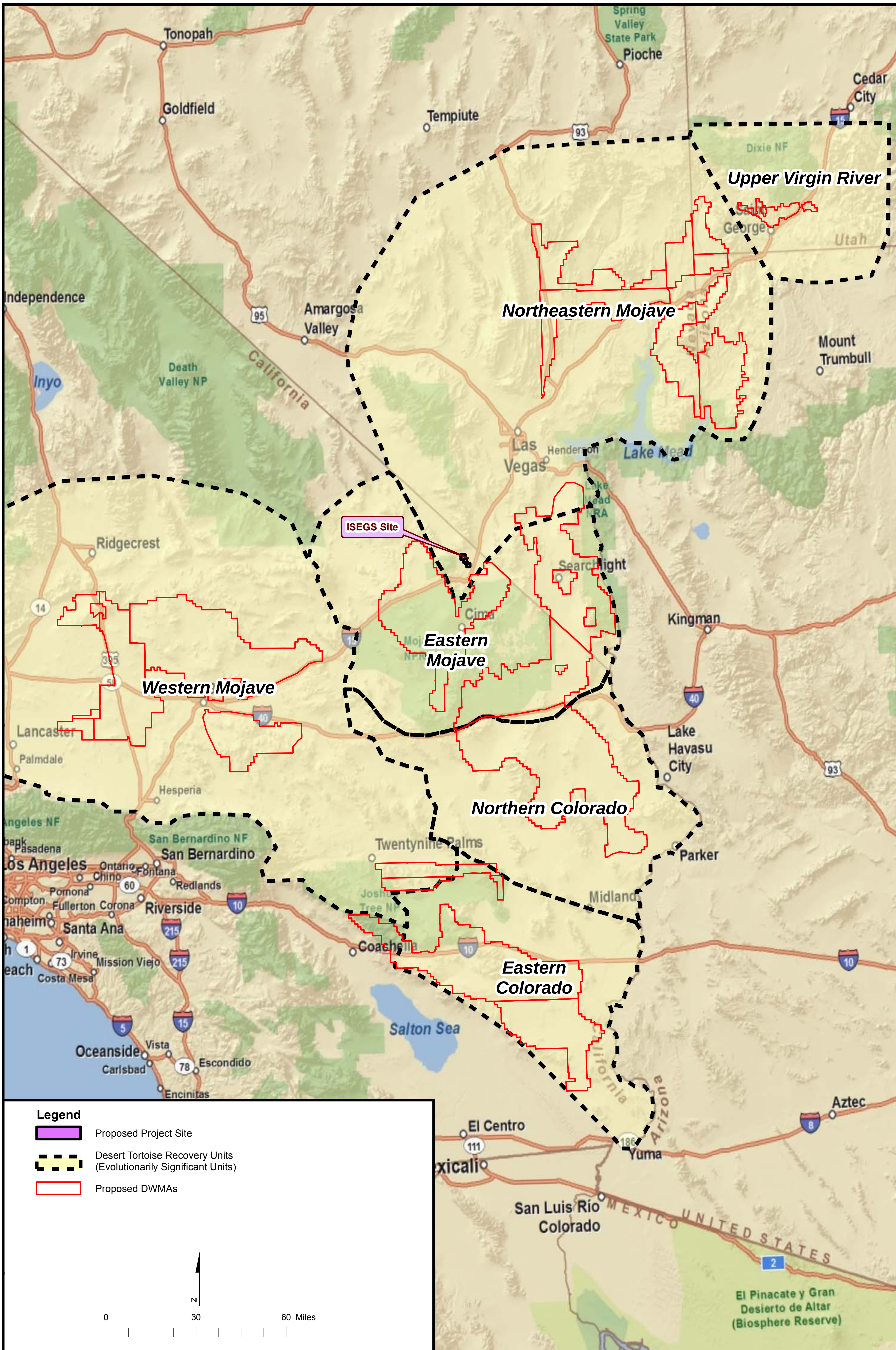

FIGURE BIO 1
APPROXIMATE BOUNDARIES OF RECOVERY UNITS OF THE DESERT TORTOISE IN THE MOJAVE REGION SHOWING LOCATION OF THE IVANPAH SEGS SITE
IVANPAH SOLAR ELECTRIC GENERATING SYSTEM

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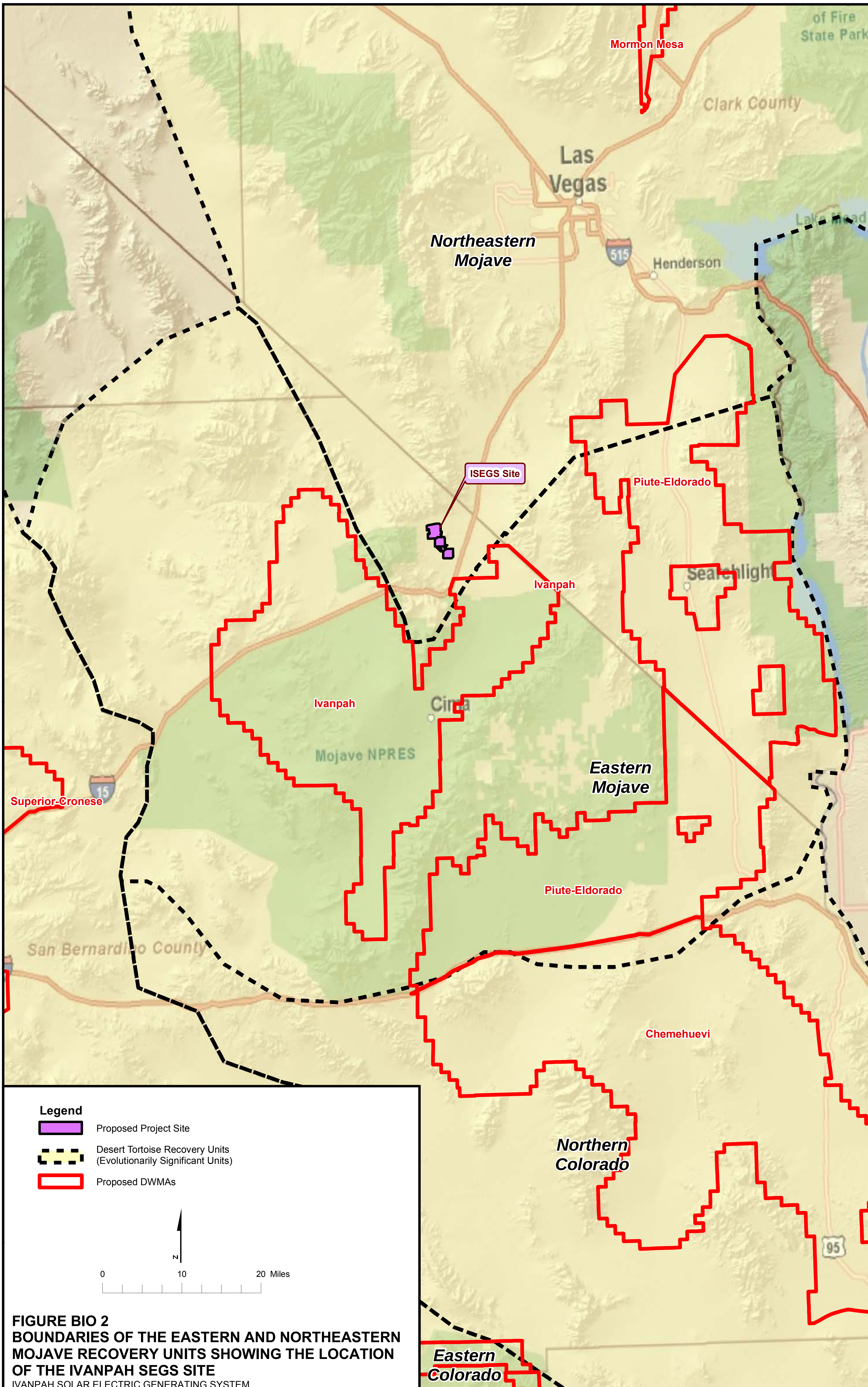

FIGURE BIO 2
BOUNDARIES OF THE EASTERN AND NORTHEASTERN MOJAVE RECOVERY UNITS SHOWING THE LOCATION OF THE IVANPAH SEGS SITE
IVANPAH SOLAR ELECTRIC GENERATING SYSTEM

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Visual Resources

I. Introduction

A. **Name:** Thomas Priestley

B. **Qualifications:** The panel's qualifications are as noted in their resumes contained in Appendix A of Applicant's Initial Testimony submitted on November 16, 2009.

C. **Prior Filings**: In addition to the statements herein, this testimony includes by reference the following documents submitted in this proceeding. These documents are in addition to those previously submitted with Applicant's Initial Testimony.

- Mona Daniels/Outdoor Recreation Planner with BLM Needles Field Office. 2010. Personal communication with Thomas Priestley/CH2M HILL. January 4. [Exhibit 84].

To the best of our knowledge, all of the facts contained in this testimony (including all referenced documents) are true and correct. To the extent this testimony contains opinions, such opinions are our own. We make these statements, and render these opinions freely and under oath for the purpose of constituting sworn testimony in this proceeding.

II. Summary of Rebuttal Testimony

These comments respond to the testimony by Laura Cunningham as filed by Basin and Range Watch. Comments are also made on the contents of Photographic Database (Exhibit 800) that was submitted to the Commission along with the Cunningham testimony.

The rebuttal comments are supported by two maps that are attached and labeled as VRT-1, Viewshed Map, Ivanpah Solar Electric Generating System and VRT-2, Project Visibility from Stateline Wilderness. VRT-1 is map that includes the project site and the areas surrounding it on all sides, extending out 5 miles or more. VRT-2 is a map on a topographic base that focuses on the Stateline Wilderness and its physical relationship to the site of the proposed project.

Both maps include overlays that indicate areas from which the proposed solar project would not be visible. Determination of the areas from which the project would not be visible was made through a Geographic Information System (GIS) viewshed analysis using the viewshed tool in 3D Analyst, an ArcGIS extension.[1] This viewshed application makes use of a 10-meter digital elevation model (DEM) downloaded from the USGS seamless data distribution center. The module calculates lines of sight between each point on the land surface and the tops of the tallest project features (in this case, the seven receiving towers) and notes whether there would be an unobstructed view toward those features. Once the analysis is complete, the results can be used to create maps of the areas from which the

[1] ESRI's ArcGIS platform is the standard GIS software package used worldwide, and its viewshed application is widely used and its results widely accepted.

project features would be visible, or conversely, the areas from which it would not be visible. In this case, the results were used to create a map that identified the areas from which no part of the project would be visible. The analysis presented in both figures is conservative in that it is based on analysis of the potential visibility of the project's tallest elements, and considers only the effects of topographic features on the view, and does not take into effect objects above the surface that may affect visibility such as tall shrubs, trees, and manmade structures.

Cunningham Testimony, Point 6, Comments Related to the Stateline Wilderness

Ms. Cunningham's statement in Point 6 of her testimony [p. 2 of her testimony] that the Ivanpah SEGS project would be visible from many locations within the Stateline Wilderness is an oversimplification. Point 5 in her testimony indicates that the experience on which the statement in Point 6 is based was a single visit that consisted of a hike "up a canyon on the west end of the wilderness, onto ridges and valleys at higher elevations, and around down past Umberci Mine." (Cunningham Testimony, page 2)

Review of Figure VRT-2, Project Visibility from Stateline Wilderness, indicates that the area described as the location of the site visit just happens to lie within the area on the southern front of the wilderness area from which the project would have the potential to be visible. Although it may be true that the project would be potentially visible from the small area of the wilderness that the intervener happened to visit, the statement that the project "would be visible from ***many areas within the wilderness***"[emphasis added] is not true. The GIS analysis of the areas from which the project would and would not have the potential to be visible has established that in 85 percent of the Stateline Wilderness, no part of the project will have the potential to be seen.

She goes on to state, "My visitor experience of the Wilderness would be negatively impacted by seeing a large industrial development so close, with glare and night lighting, as I plan to visit the wilderness again in the future. Based on my NPS experience, many visitors to Mojave National Preserve and the nearby Wilderness areas would not appreciate the desert landscape developed to such an extent so close to their boundaries. In my experience, desert recreationists are seeking the wide open vistas, natural landscapes, wildlife viewing, and wild feel of the American Southwest, and a large power plant with glare from heliostats and tower receivers could negatively affect their visit." (Cunningham Testimony, page 2)

There are a number of issues embedded in these assertions that require careful assessment:

First, the proposed project has the potential to be seen from just a small area of the wilderness on its southern edge overlooking the Ivanpah Valley. From 85 percent of the wilderness, the proposed project will not be visible, thus from most of the wilderness, the project will have no effect on views. As a consequence, from most of the wilderness, the severe impacts on visitor experience that the intervener asserts would occur would not take place.

Second, Ms. Cunningham asserts that her "experience of the Wilderness would be negatively impacted by seeing a large industrial development so close, with glare and night lighting" and that for visitors to this wilderness, "…a large power plant with glare from heliostats and tower receivers could negatively affect their visit." To assert that the project would be "so close" to viewers in the wilderness is not correct. As review of VRT-2 indicates, at the point at which the project is closest to the wilderness area, it is more than a mile away, and much of the small portion of the wilderness area from which the project has the potential to be visible lies 1.7 miles or farther from the closest edge of the project site.

KOP 9 is the viewpoint that was established for preparation of a simulation to represent the appearance of the project as seen in views from the Stateline Wilderness. As indicated in the Applicant's hearing testimony, this viewpoint is actually located approximately 0.5 mile south of the Wilderness boundary, and is thus located 0.7 miles from the closest edge of the project site, as opposed to areas within the wilderness itself from which the project may be visible, which are located from 1.12 miles to over 2.5 miles from the project site's closest edge. As a consequence, this viewpoint provides a view that is substantially closer to the project site than any potential view from within the wilderness and the simulation from it thus overstates the proximity and visual effects of the proposed project on views. Even though the simulation of the project as it would appear when seen from KOP 9 overstates the project's potential visibility and effects on views from the Stateline Wilderness, review of this simulation (FSA Visual Resources Figure 15) indicates that the project would appear to be some distance from the viewpoint, would be consistent with the forms of the 500 kV transmission lines visible in the foreground of the view. The project would be visually integrated into the view in that the solar collector towers would not appear to extend above the skyline formed by the mountain backdrop, and that the collector fields would create low, flat-appearing forms on the desert floor that would be consistent with the overall landscape pattern.

Third, Ms. Cunningham makes reference to "glare" from the heliostats and receivers as project characteristics that would have a negative effect on the visual experience of wilderness visitors. Filed and oral testimony by Yoel Gilon has addressed these assertions and has made it clear that they do not provide an accurate characterization of the project's actual effects.

Fourth, in terms of night lighting impacts on views of wilderness visitors, it is not clear that this is a relevant concern. No evidence is presented of the numbers of visitors who stay overnight in the Stateline Wilderness, or of the numbers of nighttime visitors who are likely to be in the small portion of the wilderness from which the project has the potential to be visible. The reality is that the recreation staff of the BLM Needles District office estimate that the Stateline Wilderness Area is used by an average of one visitor per day or no more than 365 users per year. The BLM recreation staff has observed that much of this use is concentrated on the eastern and northern areas of the wilderness where Stateline Pass Road provides ready access to the edge of the wilderness and to a number of washes that provide convenient hiking routes into the wilderness area's interior. BLM staff has also observed that to the extent that overnight camping takes place in the Stateline Wilderness, it is mostly concentrated in these northern and eastern areas where the landscape is the most engaging and sense of solitude is the greatest. [Exhibit 84]. It is important to note that as the viewshed pattern on Figure VRT-2 indicates, none of the project facilities (and none of any nighttime lighting that would be associated with them) would be visible from these portions of the wilderness in which the small numbers of users who camp in this wilderness would be likely to be located. Because few, if any, users of the Stateline Wilderness would have views of the project at nighttime from within the wilderness, this concern that Ms. Cunningham has expressed must be set aside.

Finally, this statement by Ms. Cunningham appears to reflect a mistaken belief that visitors to wilderness areas would expect all views from the wilderness area to remain unaltered. The presumption that all views from wilderness areas should remain forever unaltered is incorrect. When wilderness areas are established, protections are set in place for the lands within the wilderness boundary, but the wilderness legislation establishes no buffer zones in the areas around the wilderness areas to protect views looking out from the area within the boundaries. In the case of the Stateline Wilderness, the BLM, which manages most of the land in the Ivanpah Valley adjacent to and visible from the south face of this wilderness, chose to designate the valley lands as Visual Resource Management Class III, which permits development and a moderate level of visual change. If, as a result of the process of developing its Land Management Plan, the BLM had decided that it was important to preserve the views from the Stateline Wilderness toward the Ivanpah Valley, it would have assigned a more restrictive Visual Resource Management Class to them.

Cunningham Testimony, Point 7, View by Hikers in the Eastern Foothills of Clark Mountain

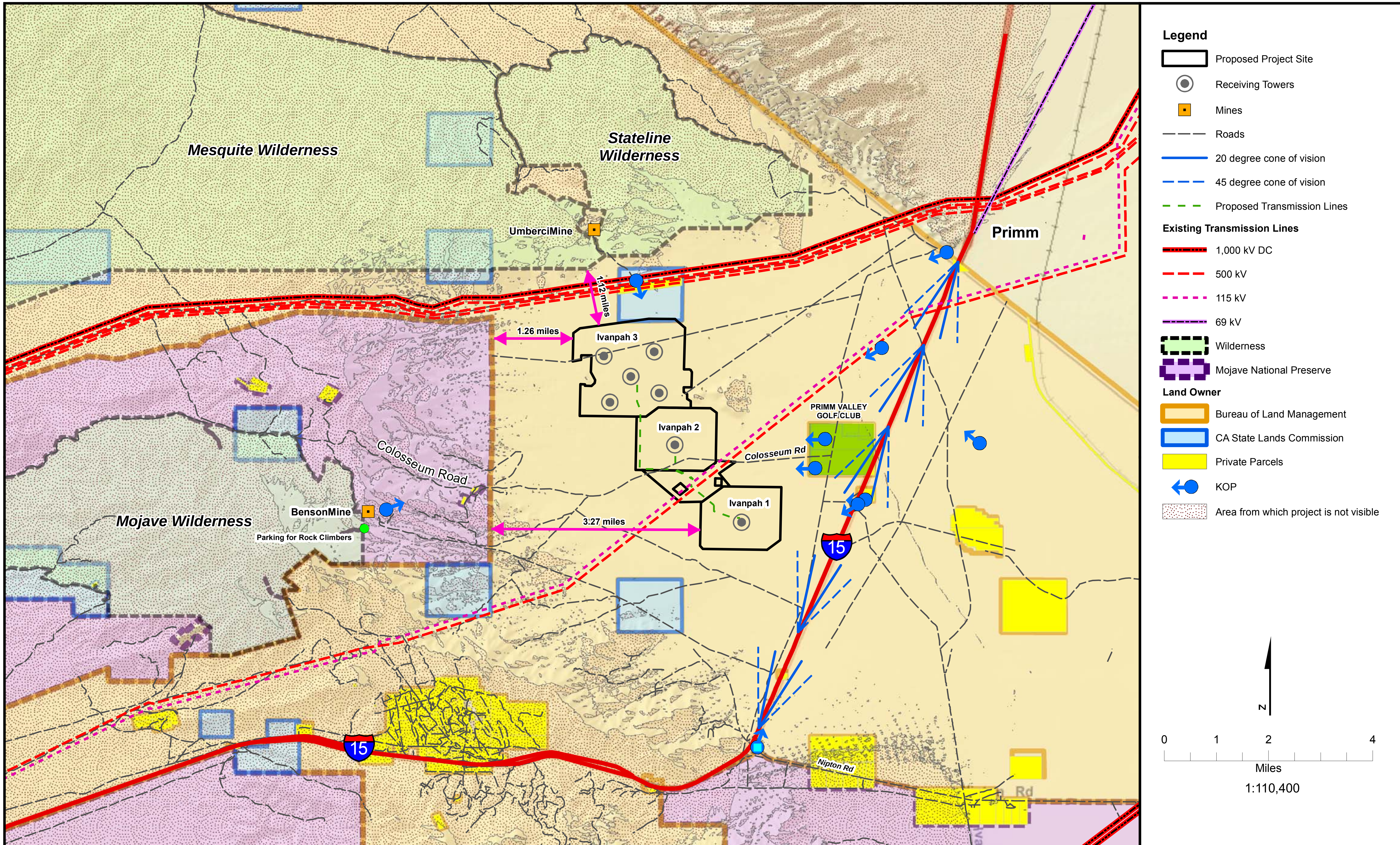
In item 7, Ms. Cunningham stated, "I visited the eastern foothills of Clark Mountain within Mojave National Preserve on 27 November 2009, and during the entire hike up a ridge the entire project site was visible. If this development were to occur, it would dominate the view for hikers on the east side of the mountain. On this hike I saw fresh scat, tracks, and beds of bighorn sheep. This ridge is approximately 2 miles from Willow Spring down in a canyon at the top of the fan along Coliseum Mine Road. Again, my visitor experience would be negatively impacted by a large industrial development next to the Preserve." (Cunningham Testimony, page 2)

There are a number of issues embedded in this statement that deserve to be looked at in detail.

One of the presumptions in this statement is that the proposed project would be developed "next to the Preserve." As review of Figure VRT-1 indicates, this presumption is false. As Figure VRT-1 makes clear, the western edges of the project site range from 1.26 mile to well over 3 miles in distance from the easternmost boundary of the preserve. From Willow Spring, which is mentioned as a point of reference in describing the hike taken on November 27, the closest edges of the project site would be located from 3.8 miles to 6 miles in the distance.

Although the project site may have been visible from all of the area that was hiked on November 27, it does not follow that the project site would necessarily have been the primary focus of attention or the primary contributor to the aesthetic quality of the experience. For anyone hiking up the ridges on the eastern front of Clark Mountain, Clark Mountain itself would be directly ahead, and because of its vivid and visually engaging form would be likely to be the focus of the hiker's attention. In addition as the intervener's statement suggests, the eyes of the hiker may often be focused on the ground and on the surrounding ridges in an effort to spot wildlife or signs of the recent presence of wildlife. In addition, as the intervener's photographic database suggests, the vegetative cover on the eastern front of Clark Mountain is visually rich, and could be expected to keep the hiker's visual focus on the area in the immediate vicinity of the trail to permit the vegetation to be observed and enjoyed close-up.

The statement that "If this development were to occur, it would dominate the view for hikers on the east side of the mountain" is an assertion and not a statement of fact. FSA Figure 16 includes a view from the eastern foothills of Clark Mountain as it now appears and a simulation of this view as it would appear with the project in place. Review of this figure indicates that although the project would be seen as a new element in the Ivanpah Valley below, it would not be a visually dominant element of the overall view, it would not block views of important elements of this vista, and the heliostat fields would create forms that would be consistent with the forms of the dry lakes that are now a part of this landscape. Review of the simulation also indicates that the use of the term "industrial" to describe the visual character of the project is incorrect. The connotation of the term "industrial" is of a facility where manufacturing takes place and that creates noise, pollution, and heavy truck and rail traffic. The proposed project would have none of these characteristics.



VRT-1
VIEWSHED MAP
IVANPAH SOLAR ELECTRIC GENERATING SYSTEM

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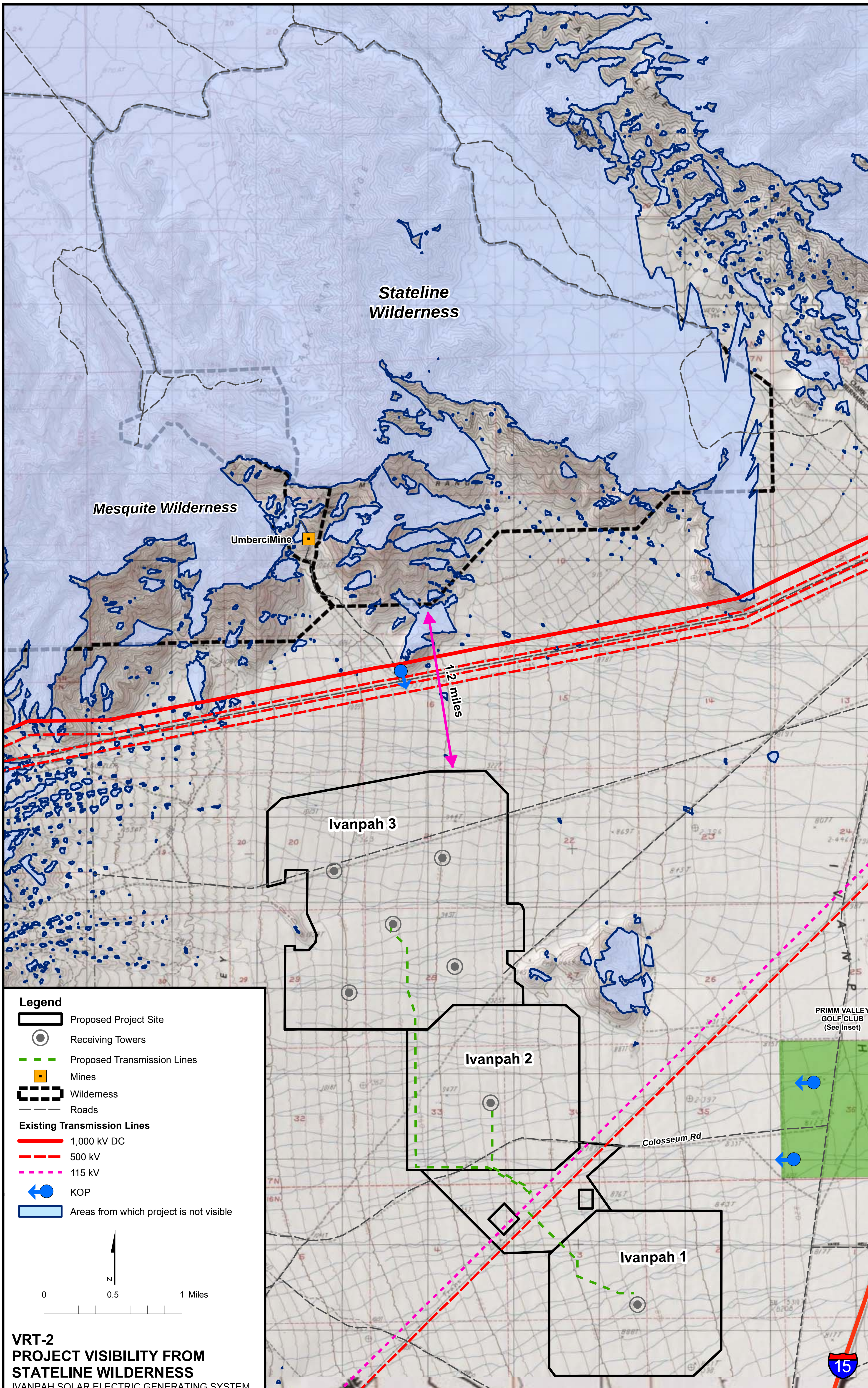

VRT-2
PROJECT VISIBILITY FROM STATELINE WILDERNESS
IVANPAH SOLAR ELECTRIC GENERATING SYSTEM

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APPENDIX A

Declarations and Resumes

DECLARATION OF
ROGER GRAY

I, ROGER GRAY, declare as follows:

1. I am presently employed by GNEX, LLC as an Electric Transmission Consultant.

2. A copy of my professional qualifications and experience were provided in Appendix A of the Applicant's Initial Testimony (filed November 16, 2009) and are incorporated herein by reference.

3. I prepared the attached testimony on Alternatives for the Ivanpah Solar Electric Generating System project based on my independent analysis, supplements thereto, data from reliable sources, and my professional experience and knowledge.

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

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

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

Dated: JAN 2 2010 Signed: [signature]

At: Alamo, California

DECLARATION OF

Arne Olson

I, Arne Olson, declare as follows:

1. I am a Partner at Energy and Environmental Economics, Inc. (E3).

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

3. I prepared the attached testimony on Alternatives for the Ivanpah Solar Electric Generating System project based on my independent analysis, supplements thereto, data from reliable sources, and my professional experience and knowledge.

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

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

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

Dated: December 31, 2009 Signed: Arne Olson

At: San Francisco, CA

Arne Olson

101 Montgomery St. Suite 1600, San Francisco, CA 94104 415.391.5100
arne@ethree.com

Mr. Olson is a lead in the practice areas of Resource Planning; Renewables and Emerging Technology; Transmission Planning and Pricing; and Energy and Climate Policy. He is an expert in evaluating the impacts of aggressive state and federal policies to promote clean and renewable energy production. He was the lead investigator for the California Public Utilities Commission in its 33% RPS Implementation Analysis and in recommending reforms to the California utilities' Long-Term Procurement Plans. He served as advisor, facilitator and drafter to the Idaho Legislature in developing Idaho's first comprehensive, statewide energy plan in 25 years. He served as lead negotiator for wholesale electricity market design on behalf of the BC Hydro and Power Authority, and he has evaluated the cost-effectiveness of long-distance transmission lines to harvest remote renewable resources for many utilities in the Western US and Canada. His clients include the California Public Utilities Commission, the Western Electric Industry Leaders' Group, the State of Idaho, the City of Seattle, Pacific Northwest Generating Cooperative, Lower Valley Energy, Pacific Gas & Electric Company, Bonneville Power Administration, Powerex, TransElect, BC Hydro, Hydro-Quebec TransEnergie, and Hawaiian Electric Company.

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Partner 2008-present
Senior Consultant 2002-2008

Resource Planning:

- Currently serving as lead investigator in assisting the California Public Utilities Commission (CPUC) in its efforts to reform the long-term procurement planning process in order to allow California to meet its aggressive renewable energy and greenhouse gas reduction policy goals.
- Constructed an integrated resource plan (IRP) on behalf of Umatilla Electric Cooperative, a 200-MW electric cooperative based in Hermiston, Oregon. The IRP considered a number of different resource and rate product options, and addressed ways in which demand-side measures such as energy efficiency, distributed generation and demand response can help UEC reduce its wholesale energy and bulk transmission costs.
- Served as lead investigator in developing integrated resource plans for numerous publicly-owned utilities including PNGC Power, Lower Valley Energy, and Platte River Power Authority.

Renewables and Emerging Technology:

- On behalf of the CPUC, investigated a number of strategies for achieving a 33% Renewables Portfolio Standard in California by 2020, and estimated their likely cost and rate impacts using the 33% RPS Calculator, a publicly-available spreadsheet model developed for this project.
- Conducted a seminar on the current status of the solar industry to senior executives of a prominent US independent power producer in December 2009.
- Conducted a seminar for senior executives at a solar thermal project developer on valuation of solar energy by electric utilities in California and the Southwest.

- Investigated for Bonneville Power Administration (BPA) the economics and feasibility of investing in new, long-line transmission facilities connecting load centers in the Pacific Northwest with remote areas that contain large concentrations of high-quality renewable energy resources. The study informed BPA about cost-effective strategies for procuring renewable energy supplies in order to meet current and potential future renewable renewables portfolio standards and greenhouse gas reduction targets.
- Co-authored *Load-Resource Balance in the Western Interconnection: Towards 2020*, a study of west-wide infrastructure needs for achieving aggressive RPS and greenhouse gas reduction goals in 2020 for the Western Electric Industry Leaders (WEIL) Group, comprised of CEOs and executives from a number of utilities through the West, and presented results indicating that developing new transmission infrastructure to integrate remote renewable resources can result in cost savings for consumers under aggressive policy assumptions.
- Conducted screening studies of long-distance transmission lines connecting to remote renewable energy zones for PG&E, BPA and Powerex.
- Assisted in the development of a methodology for evaluating the renewable energy benefits of the Sunrise Powerlink transmission project in support of expert testimony on behalf of the California ISO.

Transmission Planning and Pricing:

- Currently retained by the WEIL Group to provide capital cost assumptions to the Western Electric Coordinating Council for use in its 2009 Transmission Expansion Planning and Policy Committee Study Report.
- Currently retained by a consortium of southwestern utilities and state agencies including the Wyoming Infrastructure Authority, Xcel Colorado, Public Service Company of New Mexico, and the Salt River Project to perform an economic feasibility study of the proposed High Plains Express (HPX) transmission project, a roadmap for transmission development in the Desert Southwest and Rocky Mountain.
- Provided assistance to the Seattle City Council to develop guidelines for the evaluation of large electric distribution and transmission projects by Seattle City Light (SCL). Guidelines specified the types of evaluations SCL should perform and the information the utility should present to the City when it seeks approval for large distribution or transmission projects.
- Evaluated for Powerex the economics of developing long-distance transmission lines linking demand regions in the US Pacific Northwest and California with potential supply regions in BC, Montana, Wyoming, Nevada and New Mexico.
- Assisted British Columbia Transmission Corporation and Hydro-Quebec TransEnergie with open access transmission tariff re-design.
- Represented BC Hydro in RTO West market design process in areas of congestion management, ancillary services, and transmission pricing.

Energy and Climate Policy:

- Served as advisor, facilitator and drafter to the Interim Committee in developing Idaho's first comprehensive, statewide energy plan in 25 years. The Interim Committee and subcommittees held 18 days of public meetings and received input from dozens of members of the public in developing state-level energy policy recommendations. This process culminated in Mr. Olson drafting the 2007 Idaho Energy Plan, which was approved by the Legislature and adopted as the official state energy plan in March 2007.
- Developed a model that forecasted renewable and conventional generating resources in the WECC region in 2020 as part of an E3 project to advise the California Public Utilities Commission, California Energy Commission and California Air Resources Board about the cost and feasibility of reducing greenhouse gas emissions in the electricity and natural gas sectors.

WASHINGTON OFFICE OF TRADE AND ECONOMIC DEVELOPMENT Olympia, WA
Senior Energy Policy Specialist 1996-2002

- **Electricity Transmission***:* Lead responsibility for developing and representing agency policy interests in a variety of regional forums, with a primary focus on pricing and congestion management issues. Lead negotiator on behalf of agency in IndeGO and RTO West negotiations in areas of Congestion Management, Ancillary Services, and Transmission Planning. Participated in numerous subgroups developing issues including congestion zone definition, nature of long-term transmission rights, and RTO role in transmission grid expansion.
- **Western Regional Transmission Association, 1996-2001:** Member, WRTA Board of Directors. Participated in WRTA Tariff, Access and Pricing Committee. Participated in sub-groups examining "seams" issues among multiple independent system operators in the West and developing a proposal for tradable firm transmission rights in the Western interconnection.
- **Wholesale Energy Markets:** Monitored and analyzed trends in electricity, natural gas and petroleum markets. Editor and principal author of Convergence: Natural Gas and Electricity in Washington, a survey of the Northwest's natural gas industry in the wake of the extreme price events of winter 2000-2001, and on the eve of a significant increase in demand due to gas-fired power plants. Authored legislative testimony on the ability of the Northwest's natural gas industry to meet the demand from new, gas-fired power plants.
- **Electricity Restructuring:** Co-authored Washington Electricity System Study, legislatively-mandated study of Washington's electricity system in the context of ongoing trends and potential methods of electric industry restructuring. Authored legislative testimony on the impact of restructuring on retail electricity prices in Washington, electric industry restructuring and Washington's tax system, and the interactions between restructured electricity and natural gas markets.
- **Energy Data:** Managed three-person energy data team that collected and maintained a repository of state energy data. Developed Washington's Energy Indicators, a series of policy benchmarks and key trends for Washington's energy system; second edition published in January 2001.

DECISION ANALYSIS COROPORATION OF VIRGINIA Vienna, VA
Associate 1993-1996

- **Energy Modeling and Analysis:** Developed energy demand forecasting models for Energy Information Administration's National Energy Modeling System. Results are published each year in EIA's Annual Energy Outlook.

Education

University of Pennsylvania Philadelphia, PA
Institut de Francais du Petrole Paris, France
M.S., International Energy Management & Policy

University of Washington Seattle, WA
B.S., Mathematical Sciences, B.S Statistics

Citizenship

United States

Refereed Papers

1. *Olson A., R. Orans, D. Allen, J. Moore, and C.K. Woo (2009) "Renewable Portfolio Standards, Greenhouse Gas Reduction, and Long-line Transmission Investments in the WECC," Electricity Journal, forthcoming.*

2. *Moore, J., C.K. Woo, B. Horii, S. Price, A. Olson (2009) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, forthcoming.*

3. *Woo, C.K., I. Horowitz, N. Toyama, A. Olson, A. Lai, and R. Wan (2007) "Fundamental Drivers of Electricity Prices in the Pacific Northwest," Advances in Quantitative Analysis of Finance and Accounting, 5, 299-323.*

4. *Lusztig, C., P. Feldberg, R. Orans, and A. Olson (2006) "A survey of transmission tariffs in North America," Energy-The International Journal 31, 1017-1039.*

5. *Woo, C.K., A. Olson, I. Horowitz and S. Luk (2006) "Bi-directional Causality in California's Electricity and Natural-Gas Markets," Energy Policy, 34, 2060-2070.*

6. *Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA, 34:1, 70-80.*

7. *Woo, C.K., A. Olson and R. Orans (2004) "Benchmarking the Price Reasonableness of an Electricity Tolling Agreement," Electricity Journal, 17:5, 65-75.*

8. *Orans, R., A. Olson, C. Opatrny, Market Power Mitigation and Energy Limited Resources, Electricity Journal, March, 2003.*

Research Reports

1. *California Public Utilities Commission, 33% Renewables Portfolio Standard Implementation Analysis, Preliminary Results, June 2009, contributor.*

2. *California Public Utilities Commission, Energy Division Straw Proposal on LTPP Planning Standards, June 2009, contributor.*

3. *Load-Resource Balance in the Western Interconnection: Towards 2020, Western Electric Industry Leaders Group, January 2008, co-author, http://www.weilgroup.org/E3_WEIL_Complete_Study_2008_082508.pdf.*

4. *Olson, A., Umatilla Electric Cooperative 2008 Integrated Resource Plan, January 2009*

.

5. *Olson, A., Lower Valley Energy 2007 Integrated Resource Plan Update, February 2007.*

6. *Idaho Legislative Council Interim Committee on Energy and Technology and Energy and Environmental Economics, Inc., 2007 Idaho Energy Plan, January 2007. http://www.legislature.idaho.gov/sessioninfo/2007/energy_plan_0126.pdf*

7. *Olson, A., Base Case Integrated Resource Plan for PNGC Power, April 2006.*

8. *Olson, A., Integrated Resource Planning for Coos-Curry Electric Cooperative, August 2005.*

9. *Orans, R. and A. Olson, Integrated Resource Planning for Lower Valley Energy, December 2004.*

10. *Orans, R., C.K. Woo, B. Horii, S. Price, D. Lloyd, A. Olson, C. Baskette and J. Swisher, "A Forecast Of Cost Effectiveness: Avoided Costs And Externality Adders", prepared for the California Public Utilities Commission, February 2004.*

11. *Orans, R., C.K. Woo, and A. Olson, Stepped Rate Design Report, prepared for BC Hydro and filed with the BCUC, May 2003.*

12. *Convergence: Natural Gas and Electricity in Washington, editor and principal author. Washington Office of Trade and Economic Development, May 2001. http://www.energy.cted.wa.gov/Papers/Convergence.htm.*

13. *Questions and Answers Concerning Impact of Current Energy Situation on Washington State's Economy, contributing author. Washington Office of Trade and Economic Development and Washington Office of Financial Management, April 2001. http://www.energy.cted.wa.gov/Energy Q&A.pdf.*

14. *2001 Biennial Energy Report: Issues and Analyses for the Washington State Legislature, contributing author. Washington Office of Trade and Economic Development, February 2001. http://www.energy.cted.wa.gov/BR2001/default.htm.*

15. *Study of Electricity Taxation, contributing author. Washington Department of Revenue, December 1999. http://www.energy.cted.wa.gov/papers/taxstudy.doc.*

16. *Washington Energy Indicators, author. Washington Department of Community, Trade and Economic Development, February, 1999. http://www.energy.cted.wa.gov/Indicators99/Contents.htm.*

17. *Washington State Electricity Study, contributing author. Washington Department of Community, Trade and Economic Development and Washington Utilities and Transportation Commission, January 1999. http://www.energy.cted.wa.gov/6560/finalapp.htm.*

18. *Our Energy Future: At a Crossroads. 1997 Biennial Energy Report, contributing author. Washington Department of Community, Trade and Economic Development, January 1997. http://www.energy.cted.wa.gov/BIENREPO/CONTENTS.HTM.*

19. *Washington State Energy Use Profile 1996, contributing author. Washington State Energy Office, June, 1996. http://www.energy.cted.wa.gov/FILES/PRFL/BASE02.HTM.*

20. *NEMS Transportation Sector Mass Transit Model: Proposed Model Structure, Results and Sensitivity Analysis, author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, August 1995.*

21. *NEMS Transportation Sector Model: Light Truck Use in Freight vs. Commercial Fleets, author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, February 1995.*

22. *Model Documentation Report: Transportation Sector Model of the National Energy Modeling System, contributing author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, March 1994.*

DECLARATION OF
W. GEOFFREY SPAULDING, Ph.D.

I, W. GEOFFREY SPAULDING, declare as follows:

1. I am presently employed by CH2M HILL Incorporated as a Senior Scientist.
2. A copy of my professional qualifications and experience were provided in Appendix A of the Applicant's Initial Testimony (filed November 16, 2009) and are incorporated herein by reference.
3. I helped prepare the attached rebuttal testimony on Alternatives for the Ivanpah Solar Electric Generating System project based on my independent analysis, supplements thereto, data from reliable sources, and my professional experience and knowledge.
4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed herein.
5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

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

Dated: January 4, 2010 Signed: W. Geoffrey Spaulding

At: Henderson, Nevada

APPENDIX B

Updated Exhibit List

Applicant's Exhibit List

Exhibit No.	Docket Log No.	Date of Document	Description	Pages
1	42174	8/28/2007	AFC Volumes 1 & 2	1890
2	42681	10/5/2007	Data Adequacy Supplement A	73
3	42916	10/19/2007	Data Adequacy Supplement B	7
4	44310	1/14/2008	Data Response, Set 1A	170
5	45318	2/11/2008	Data Response, Set 1B	59
6	45608	3/10/2008	Data Response, Set 1C	9
7	46239	5/9/2008	Data Response, Set 1D (Optimization)	71
8	47192	7/22/2008	Data Response, Set 1E	13
9	47476	8/6/2008	Data Response, Set 1F	104
10	47983	9/10/2008	Data Response, Set 1G	41
11	48034	9/12/2008	Data Response, Set 1H	53
12	53104	10/24/2008	Data Response, Set 1I	8
13	49332	12/8/2008	Data Response, Set 1J	7
14	51717	5/27/2009	Data Response, Set 1K	73
15	51790	6/2/2009	Data Response, Set 1L	45
16	51799	6/3/2009	Data Response, Set 1M	10
17	52751	8/5/2009	Data Response, Set 1N	187
18	52872	8/13/2009	Data Response, Set 1O	8
19	53176	9/9/2009	Data Response, Set 1P	44
20	46666	6/10/2008	Data Response, Set 2A	113
21	47190	7/22/2008	Data Response, Set 2B	180
22	47477	8/6/2008	Data Response, Set 2C	38
23	48033	9/12/2008	Data Response, Set 2D	188
24	48082	9/19/2008	Data Response, Set 2E	23
25	48371	10/2/2008	Data Response, Set 2F	40
26	49921	1/28/2009	Data Response, Set 2G	103
27	51576	5/13/2009	Data Response, Set 2H	294
28	51597	5/18/2009	Data Response, Set 2I	82
29	52054	6/17/2009	Data Response, Set 2J	49
30	52208	6/30/2009	Data Response, Set 2K	252
31	53193	9/10/2009	Data Response, Set 2KR	25
32	47533	8/12/2008	Supplemental Data Response, Set 1A	18
33	47698	8/22/2008	Supplemental Data Response, Set 1B	48
34	48014	9/12/2008	Supplemental Data Response, Set 1C	31
35	48188	9/24/2008	Supplemental Data Response, Set 1D	117
36	49121	11/21/2008	Supplemental Data Response, Set 1E	7
37	49338	12/8/2008	Supplemental Data Response, Set 1F	10
38	50610	3/19/2009	Supplemental Data Response, Set 2A	32
39	51575	5/13/2009	Supplemental Data Response, Set 2B	492
40	51612	5/19/2009	Supplemental Data Response, Set 2C	45
41	51720	5/19/2009	Supplemental Data Response, Set 2D	116
42	51804	6/3/2009	Supplemental Data Response, Set 2E	30
43	51857	6/5/2009	Supplemental Data Response, Set 2F	9
44	51884	6/9/2009	Supplemental Data Response, Set 2G	11
45	51893	6/9/2009	Supplemental Data Response, Set 2H	6
46	52819	8/10/2009	Supplemental Data Response, Set 2I	21
47	52847	8/12/2009	Supplemental Data Response, Set 2J	27
48	52549	7/23/2009	Supplemental Data Response, Set 3A	29

Applicant's Exhibit List				
Exhibit No.	**Docket Log No.**	**Date of Document**	**Description**	**Pages**
49	52922	8/20/2009	Supplemental Data Response, Set 4	10
50		6/18/2007	Air Dispersion Modeling Protocol	
51	--	8/20/2007	Cumulative Impacts Analysis	3
52	--	8/23/2007	Letter dated August 23, 2007 from Mojave Desert Air Quality Management District (Alan De Salvio) to Sierra Research (Steve Hill) describing stationary sources within 6 miles of the Project.	?
53	--	9/18/2007	Application for Authority to Construct	9
54	48246	8/28/2008	DPT 2 System Impact Study Report (CONFIDENTIAL-DOC NOT INCLUDED IN FILES)	44
55	--	11/3/2008	Comments on PDOC for Ivanpah SEGS Project	3
56	49276	12/3/2008	Final Decision / Determination of Compliance	34
57	49839	1/23/2009	PSA Comments, Set 1	53
58	45444	2/15/2008	Preliminary Decision / Determination Ivanpah Solar Electric Generating System	33
59	--	3/31/2009	Revisions to the FDOC for Ivanpah SEGS Project	5
60	51200	4/9/2009	MDAQMD's FDOC for ISEGS	42
61	--	6/24/2009	Revisions to the FDOC for Ivanpah SEGS Project	2
62	52551	7/15/2009	Ivanpah Final Determination Rev B	42
63	52788	8/7/2009	Letter to John Kessler from the Applicant regarding Applicant's Biological Resources Mitigation	7
64	52898	8/12/2009	Duration of ISEGS Grading	2
65		11/16/2009	Applicant's Testimony	787
66		11/24/2008	Interconnection System Impact Study-Final Report Ivanpah 3 (CONFIDENTIAL-DOC NOT INCLUDED IN FILES)	
67		12/9/2009	Errata to Applicant's Visual Resource Testimony	5
68			Draft EIS for the proposed DesertXpress High-Speed Passenger Train, Chapter 3.16 Cumulative Impacts	60
69			11 x 17 Viewshed Map	1
70			Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent.	22
71			Re-DEC Working Group Meeting. Potential Challenges to High Penetration of Distributed Renewable Generation	34
72			California Public Utilities Commission. 2008. Annual Report.	88
73			Email communication with Susan Sanders Regarding Desert Tortoise Translocation.	1
74			(NERC). 2009. Special Report: Accommodating High Levels of Variable Generation	104
75			Pacific Gas and Electric Company's Comments on the Energy Division's 33% RPS Implementation Analysis Preliminary Results.	14
76			SDG&E Response to Questions on 33% RPS Implementation Analysis Preliminary Results Report.	10
77			Schlesinger, W.H., J. Belnap, and G. Marion. 2009. On carbon sequestration in desert ecosystems.	3

Applicant's Exhibit List				
Exhibit No.	**Docket Log No.**	**Date of Document**	**Description**	**Pages**
78			Southern California Edison Company’s (U 338-E) Comments on, and responses to technical questions regarding, The Energy Division’s 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results.	18
79			(DOE) 2009. High Penetration Solar Deployment Projects.	2
80			Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008”	50
81			Draft Ivanpah SEGS Special-Status Plant Avoidance and Protection Plan	
82			“The golden eagle in San Diego County, California.” Condor 39:49-56. As cited in Digital-Desert.com	6
83			Water Developments and Desert Bighorn Sheep: Implications for Conservation.	6
84			Mona Daniels/Outdoor Recreation Planner with BLM Needles Field Office. 2010. Personal communication with Thomas Priestley/CH2M HILL.	1

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION
FOR THE *IVANPAH SOLAR ELECTRIC GENERATING SYSTEM*

DOCKET NO. 07-AFC-5
PROOF OF SERVICE
(Revised 11/23/09)

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DECLARATION OF SERVICE

I, John L. Carrier, declare that on January 5, 2010, I served and filed copies of the attached, Applicant's Rebuttal Testimony dated January 5, 2010. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: [www.energy.ca.gov/sitingcases/ivanpah].

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

__x__ sent electronically to all email addresses on the Proof of Service list;

_____ by personal delivery or by depositing in the United States mail at Sacramento** with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses NOT marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

__x__ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (*preferred method*);

OR

_____ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 07-AFC-5
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

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

John L. Carrier

John L. Carrier, J.D.

**or by other delivery service, e.g., Fed Ex, UPS, courier, etc.