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STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of: Petition For Amendment for the **PALEN SOLAR ELECTRIC GENERATING SYSTEM**	**DOCKET NO. 09-AFC-07C** **DECLARATION OF ARNE OLSON**

I, Arne Olson, declare as follows:

1. I am presently a partner at Energy and Environmental Economics, Inc.

2. A copy of my professional qualifications and experience is included with my Supplemental Rebuttal Testimony.

3. I prepared the attached supplemental rebuttal testimony relating to Alternatives for the Petition for Amendment for the Palen Solar Electric Generating System (California Energy Commission Docket Number 09-AFC-07C).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

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

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed on July 17 2014.

Arne Olson

Arne Olson

PALEN SOLAR ELECTRIC GENERATING SYSTEM
ALTERNATIVES
SUPPLEMENTAL REBUTTAL TESTIMONY

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 Palen Solar Holdings, LLC (PSH) to rebut the testimony of Mr. Bill Powers as it relates to a hypothetical distributed generation alternative. Mr. Powers' testimony, filed on the behalf of the Center for Biological Diversity (CBD), states that the Commission should deny PSH's application to construct the Palen Solar Electric Generating Station (PSEGS) because "there are better, feasible alternatives" including distributed PV (p. 11).

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

A. I have over 20 years of professional experience in the energy industry, the last 12 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 (CPUC) 33% RPS Implementation Analysis[1], which studied the cost and likelihood of bringing online sufficient renewable energy to meet a 33% Renewables Portfolio Standard (RPS) by 2020. In my role as advisor to the CPUCs' 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, such as through the inclusion of a "High DG" case among the cases that the CPUC's 33% RPS study considered. I also served as the technical lead and lead author of the recent E3 report, *Investigating a Higher Renewables Portfolio Standard for California*, prepared on behalf of the Los Angeles Department of Water

[1] http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

and Power (LADWP), Pacific Gas and Electric Company (PG&E), Sacramento Municipal Utilities District (SMUD), San Diego Gas & Electric Company, and Southern California Edison Company (SCE), which assesses the cost and feasibility of achieving higher levels of renewable penetration in California after 2020.[2] I have participated in many studies of the cost and technical feasibility of increased reliance on both distributed and central station renewable energy resources, including distributed PV.

I hold 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. Have you previously provided expert testimony?

A. Yes, I testified in front of this Commission regarding a distributed solar photovoltaic (DPV) alternative to the Ivanpah Solar Electric Generating Station and to the Hidden Hills Solar Electric Generating Station. I have also provided sworn expert witness testimony to the California Public Utilities Commission and the Alberta Utilities Commission.

Q. How is your testimony organized?

A. I have organized my rebuttal testimony based on the headings in Mr. Powers' direct testimony that address the DPV alternative.

Section II. Distributed Solar Alternatives to PSEGS

A. Large-Scale Distributed Rooftop PV

Q. Mr. Powers cites Southern California Edison's (SCE) 2008 application to acquire up to 500 MW of distributed PV (pp. 3-4). Was this program successful at achieving the goal of 500 MW of distributed PV?

A. No, it was not. Mr. Powers' reference is very outdated. SCE was able to acquire only 98.8 MW (69.7 MW of which was on rooftops) under its distributed PV program before petitioning the CPUC to reduce its targets

[2] https://ethree.com/public_projects/renewables_portfolio_standard.php

in February 2011[3]. It has since incorporated the remaining megawatts from this program into its Renewable Auction Mechanism (RAM) program. RAM projects may be up to 20 MW in size. Given cost efficiencies of larger, ground-mounted solar installations, winning bid projects in the RAM program for SCE and the other investor-owned utilities (IOUs) have not been located on rooftops to date and are highly unlikely to be in the future.

Q. Mr. Powers states that utility-procured distributed PV should be considered a feasible alternative to a central station solar thermal project, because "individual rooftop PV arrays in a large distributed PV project are functionally equivalent to single rows of reflective mirrors in a solar thermal project" (p. 5). Do you agree with this perspective?

A. No, I do not. The heliostats in a solar thermal project reflect solar irradiation to a common gathering point, concentrating heat that is used to spin a turbine for power generation. The resulting generating station is different from a collection of rooftop PV arrays for a number of reasons: it concentrates the solar energy to produce a much higher capacity factor (32.2% for PSEGS, as opposed to 15-20% for rooftop PV); it uses a rotating turbine to generate power; it has desirable operating characteristics including inertia, the ability to provide voltage support, and some amount of generation flexibility.

In addition, the project development effort is very different for rooftop PV relative to PSEGS. Assuming an average size of 500 kW for commercial rooftops, and taking into consideration the difference in capacity factor between rooftop PV and PSEGS, it would require 1,500 - 2,000 individual rooftop PV projects to equal the energy production of PSEGS. This would require the identification of thousands of different potential sites, individual rooftop lease negotiations with thousands of building owners, and individual power purchase agreements for each project. This is a vastly different undertaking than developing a single, 500 MW solar power tower project.

[3] http://www3.sce.com/sscc/law/dis/dbattach10.nsf/0/8825781C0074664D882578350005A25D/$FILE/A.08-03-015+Solar+PV_SCE+PFM+of+D.09-06-049.pdf

B. Small-scale: Major Unanticipated Increase in Rooftop PV by mid-2017

Q. Mr. Powers asserts the California Solar Initiative requires the California IOUs to have 1,940 MW of customer cited PV online by 2016 (pp. 5). Is this accurate?

A. No, it is not. Mr. Powers' testimony refers to the California Solar Initiative goals as mandates, when they are actually objectives of the incentive program. In reality, PG&E, SCE, and California Center for Sustainable Energy (CCSE) in SDG&E territory are merely the program administrators for the main incentive program component of CSI[4].

Q. Mr. Powers states that AB 327 establishes "minimum statutory net-metering rooftop solar targets to be met by the IOUs by mid-2017. AB 327 established a statutory mandate to add up to 5,256 MW of solar energy resources in California" (pp. 5). Is this accurate?

A. No, it is not. AB 327 does not establish (pp. 5) a statutory mandate for the IOUs to add or interconnect rooftop PV. Rather, it establishes a *ceiling* on *customer-owned* PV allowed under current net energy metering (NEM) rules[5].

Q. Mr. Powers claims that "at a minimum, the IOUs by law will add 3,316 MW of additional net-metered solar by 2017" (p. 5) and that this "will have the effect eliminating the need for approximately 1,100 MW of RPS-eligible solar capacity" (p. 6). Are these claims accurate?

A. No, they are not, for two reasons. First, Mr. Powers' calculations are not accurate. Mr. Powers assumes rooftop systems have a capacity factor of 20-21%, while actual CSI data has shown capacity factors of between 15% and 20%, depending on climate zone, with the state average being 17-18%[6]. Using a more realistic capacity factor of 17.5% for rooftop PV, 3,316 MW would produce approximately 5,083 GWh of energy, displacing 1,678 GWh of RPS-eligible renewables due to the consequent reduction in retail sales. This is approximately the quantity of energy that would be

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[4] Exhibit 3114 CPUC webpage, About the California Solar Initiative, last modified January 31, 2014: http://www.cpuc.ca.gov/PUC/energy/Solar/aboutsolar.htm.

[5] AB 327: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

[6] CEC-400-2013-005-D, pp. 13: http://www.energy.ca.gov/2013publications/CEC-400-2013-005/CEC-400-2013-005-D.pdf

produced by a 600 MW solar thermal plant operating at a capacity factor of 32%, not the 1,100 MW claimed by Mr. Powers.

Second, full subscription of the new NEM cap is a forecast that *customers* will add this quantity of capacity by July, 2017, but this in no way is a minimum and the IOUs have no control over how much capacity is actually built.

C. Net-Metered Rooftop PV

Q. Do renewable energy credits (RECs) generated by behind-the-meter PV count toward RPS compliance?

A. Yes, under California's 33% RPS statute, RECs generated by behind-the-meter PV facilities can be counted toward a load-serving entity's (LSE's) RPS compliance obligation if the LSE purchases the REC from the system owner. However, under current CPUC rules, these RECs fall into Category 3. Category 3 RECs can be used for only 10% of an LSE's total RPS-compliant energy in 2020[7].

Q. In practical terms, what is the impact of new behind-the-meter PV in helping California LSE's reach the 33% RPS requirement in 2020?

A. The practical impact of new behind-the-meter PV is to offset RPS energy requirements by 33% of the system's generation, as indicated in my calculation of this effect above. The 33% reduction is a result of the behind-the-meter system offsetting retail electricity sales. Beyond this, new behind-the-meter PV does not help California LSE's reach the 33% RPS requirement in 2020 for two reasons:

1) The supply for Category 3 RECs far exceeds current and future projected demand. This is because demand is capped at 10% of RPS energy in 2020 and because Category 3 RECs include any RPS-eligible energy generated in the Western Interconnection and not used elsewhere for policy compliance, such as wind resources in Oregon, Idaho and Montana that are currently under contract to California IOUs. Currently, a surplus of supply exists for Category 3 RECs.

2) The sale of Category 3 RECs requires transaction on the Western Renewable Energy Generation Information System

[7] D.11-12-052 http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/156060.PDF

(WREGIS) and revenue-grade metering. These requirements mean that "Although distributed generation (DG) facilities produce RPS-eligible energy and renewable energy credits that, as a technical matter, can be sold into the California RPS compliance market, as a practical matter the ability to do so is not feasible due to additional costs that are incurred in order to bring the RECs to market.[8]"

Thus, due to the very low market prices for Category 3 RECs and the high transaction costs for selling those RECs into the marketplace, it has not been practical for the IOUs to use behind-the-meter PV as a supply source for RPS compliance.

Q. Are there other considerations regarding the use of RECs from customer-sited PV for RPS compliance?

A. Yes, I believe that using RECs from customer-sited PV installations is counter to the purpose that most customers had in mind when installing the PV systems. By selling the RECs to the LSE, system owners would no longer be able to claim the renewable attribute for themselves. Having sold the "green" attribute to the utility, they would, effectively, be served with "brown" power from the grid, despite having PV system on their roofs. This is because the rooftop PV system would not be *incremental* to the renewables that would otherwise be built. Instead, it would simply replace a renewable facility that would otherwise have been built elsewhere.

It is my belief that many, if not most, homeowners who install rooftop PV systems do so *not* because they wish to become independent power producers selling renewable energy to the utility at a profit and displacing renewable projects in other locations, but rather because they wish to serve their own energy needs with renewable power and displace fossil generation that emits harmful air pollution. In service of that goal, as a policy matter I believe that RECs generated by rooftop systems should be considered "retired" by the system owners, and not available for sale in the secondary market.

[8] Comments to the California Energy Commission on the Scope of RPS Eligibility Guidebook Revisions, Docket 11-RPS-01, Submitted February 18th, 2014 by the California Solar Energy Association. http://www.energy.ca.gov/portfolio/documents/2014-01-28_workshop/comments/California_Solar_Energy_Industries_Association_Comments_2014-02-18_TN-72683.pdf

Q. Should the Commission consider the potential for customer-sited PV installations to be a viable project alternative to PSEGS?

A. No, it should not. Distributed, customer-sited PV is installed and maintained entirely at the discretion of individual utility customers. Customers make the decision whether or not to invest in PV based on their own economic and/or altruistic motivations. Thus, while *programs* can encourage the adoption of distributed PV that in aggregate can equal the output from a single larger system, customer-sited PV is not a *project* sponsored by or under the control of the utilities. The collection of individual actors needed to install customer-sited PV to equal a single utility-scale project makes it impractical to consider this model as a direct substitute for PSEGS.

D. Impact of Higher-Than-Anticipated Distributed PV on RPS Procurement

Q. Mr. Powers claims that the state is projecting no growth in electricity consumption over the 2014-2024 timeframe, and that "SCE will require somewhat less RPS-eligible resources in 2024 than in 2014 to meet the 33 percent RPS requirement" (pp. 6). Is this statement accurate?

A. No, this statement is misleading because it refers to a high energy efficiency *sensitivity* case, not the primary case that is used for electric sector planning. The CEC produced three forecasts of Additional Achievable Energy Efficiency (AAEE): Low, Mid and High. When combined with the Mid-demand baseline in the CEC forecast, the net annual growth rates of electricity consumption are 0.71% for the Low-Mid AAEE scenario, 0.42% for the Mid AAEE scenario, and 0% for the High-Mid AAEE scenario.[9] For planning purposes, the primary scenario used is the Mid AAEE scenario with annual load growth of 0.42%, not the High-Mid AAEE scenario cited by Mr. Powers. This means that utility load, and the need for renewable energy to serve 33% of that load in compliance with the RPS, will continue to grow over time.

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[9] CEC, California Energy Demand 2014-2024 Final Forecast LSE and Balancing Authority Forecasts, Form 1.1c, April 15, 2014. See: http://www.energy.ca.gov/2013_energypolicy/documents/demandforecast_CMF/LSE_and_Balancing_Authority_Forecasts/.

Q. Mr. Powers claims peak load in the CAISO service territory has declined since 2006 (pp. 7), is this accurate?

A. Yes, peak load in 2013 was 45,097 MW while 50,270 MW in 2006. However, this comparison of annual peaks is misleading due to fluctuations in extreme weather events from year to year. The year 2006 is notable for being the hottest summer ever on record in California. [10] Hence, a short-term comparison between 2006 and any other year will be highly misleading. While it is true that CAISO peak load has not grown in recent years due to the recession and a series of mild summers, the CEC's Mid AAEE case projects that CAISO peak load will grow by 0.33% per year between 2014 and 2024, after including the impact of behind-the-meter PV.[11]

Section III. Battery Storage

Q. Mr. Powers states that the energy storage targets adopted by the commission are mandatory and must be met by the utilities (pp. 7). Is this true?

A. While it is true that AB 2514 and CPUC Decision D.13-10-040 mandate that California utilities procure a certain amount of storage, there is both flexibility in reaching the targets and uncertainty in the total storage that will be procured. This uncertainty arises because AB 2514 requires that energy storage targets and procurements must be "viable and cost-effective."[12] Under D.13-10-040, the IOUs are able to defer up to 80 percent of their procurement targets if costs are unreasonable or due to an uncompetitive number of bids.[13]

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[10] Kozlowski, D. R. and L. M. Edwards. 2007. An analysis and summary of the July 2006 record-breaking heat wave across the state of California. NOAA Western Regional Tech Attach, No. 07-05 (February 27, 2007), Salt Lake City, Utah. http://www.wrh.noaa.gov/wrh/07TAs/ta0705.pdf

[11] CEC, California Energy Demand 2014-2024 Final Forecast LSE and Balancing Authority Forecasts, Form 1.1c, April 15, 2014. See: http://www.energy.ca.gov/2013_energypolicy/documents/demandforecast_CMF/LSE_and_Balancing_Authority_Forecasts/.

[12] AB 2514, Energy storage systems.

[13] Exhibit 3119 D.13.10-040, Conclusion of Law 28 at pp. 74.

Q. Mr. Powers argues that it would be difficult to economically justify authorizing energy storage to be built outside of the LA Basin load pocket because it would not contribute local capacity value (pp. 8). Under the storage mandate, *if* all 1,325 MW were built, how much local capacity value would be provided to the LA Basin?

A. As seen in the table below[14], the mandate for SCE, which serves the LA Basin, is 580 MW of the 1,325 MW. Thus, at least 745 MW would be procured by PG&E and SDG&E outside of the LA Basin. In addition, part of SCE's service area is outside of the LA Basin load pocket; hence, 580 MW is an upper bound on the quantity of storage that would be located in the LA Basin.

Table 2: Energy Storage Procurement Targets by Utility

Energy Storage Procurement Targets (in MW)

Storage Grid Domain (Point of Interconnection)	2014	2016	2018	2020	Total
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal SCE	**90**	**120**	**160**	**210**	**580**
Pacific Gas and Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal PG&E	**90**	**120**	**160**	**210**	**580**
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Subtotal SDG&E	**20**	**30**	**45**	**70**	**165**
Total - all 3 utilities	**200**	**270**	**365**	**490**	**1,325**

Q. If storage were located at PSEGS, could it contribute to SCE's storage mandate?

A. Yes, thermal storage located at PSEGS could contribute to SCE's 310 MW transmission level storage mandate through its interconnection with the SCE system at the Red Bluff Substation.[15] In addition, due to flexibility between the categories, storage at PSEGS could be used to satisfy up to 80% of SCE's distribution level requirement, or 148 MW. Thus, storage at the PSEGS site could contribute a total of 458 MW toward SCE's 580 MW mandate.

[14] Exhibit 3119 D.13.10-040, Appendix A at pp. 2.
[15] Exhibit 3119 D.13.10-040, Table 1 at pp. 14.

Section IV. PV and PSEGS Cost Comparison

A. PV Without Battery Storage vs. PSEGS Without Storage

Q. Mr. Powers states that "Relatively small PV installations are now being built for less than $2000/kW". Are these cost quotes for distributed PV facilities located in the LA Basin load pocket?

A. No, these quotes are for utility-scale (10 MW) projects located in New Mexico.

Q. Mr. Powers claims that "twenty 500-kW rooftop projects can be bundled as a single 40 MW project to achieve the same economies of scale necessary to achieve a capital cost price point at or near $2,000/kW" (pp 10.). Does he present any evidence that it is possible for 20 separate rooftop projects in California to achieve the same $/watt installed cost as a single ground mounted system installed in New Mexico?

A. No, he does not. Rooftop projects have very different economics than ground-mounted projects. Each rooftop retrofit project requires custom design work, project staging, etc. In addition, rooftop systems cannot take advantage of single-axis tracking, have restrictions on maximum tilt, and tend to be located in areas with significantly less insolation than larger, central station installations. Hence, rooftop projects typically cost significantly more than larger, ground-mounted projects.

Q. What are the latest publicly available prices for actual DPV installations in California?

A. The average installed cost across all system sizes in the CSI program from the first quarter of 2014 was $5.36/Watt-AC, or $5,360/kW. Over the previous year, the average cost of systems smaller than 10 kW was $5.67/Watt-AC and $5.22/Watt-AC for systems larger than 10 kW (updated July 9, 2014).[16] This is significantly higher than the $2/Watt cited by Mr. Powers.

[16] CSI solar statistics: http://www.californiasolarstatistics.ca.gov/

B. PV With Battery Storage vs. PSEGS With Storage

Q. Mr. Powers suggests that battery storage could be added to the cost of a rooftop PV system for a total installed cost of $3,500/kW ($2,000/kW for the PV system and $1,500/kW for the battery system), significantly less than the cost of solar thermal with storage of $7,750/kW. Do you agree with these numbers?

A. No, I do not. First, the cost Mr. Powers cites for solar thermal includes six hours of thermal storage, whereas the costs he cites for battery storage for rooftop PV include only 3 hours of storage. Thus, the two systems he compares are not at all equivalent. Taking Mr. Powers' cost numbers at face value, it would require $3,000/kW of battery storage, in addition to the PV system costs, to provide the 6 hours of storage that is incorporated into the solar thermal cost he cites.

Second, the $2,000/kW cost he cites is a pre-construction estimate for a ground-mounted project in New Mexico. Actual costs for installed rooftop systems in California averaged $5,360/kW during the first quarter of 2014, according to statistics from the California Solar Initiative. A rooftop PV installation with 6 hours of storage would therefore cost $8,360/kW,[17] higher than the $7,750/kW he cites for solar thermal with 6 hours of storage. In addition, we have seen that the solar thermal facility would operate at a significantly higher capacity factor (approximately 32% as compared to 17% for the rooftop PV system, before considering the effects of the storage).

Q. Mr. Powers claims that 3 hours of storage is "sufficient for the PV system to act as a completely reliable early evening peaking power system when electricity demand and power prices are high", which provides "economically "right-sized" energy storage capacity tailored for current and foreseeable energy market conditions." Does he provide any evidence to support his contention that 3 hours of storage is "right-sized"?

A. No, he does not. A study conducted by my firm, *Investigating a Higher RPS for California,* indicates that 6-10 hours of storage may be needed to soak up system-wide overgeneration that occurs between during daylight

[17] In addition, this assumes that the upfront battery cost is the only cost additional to the PV system. Other costs to consider, to produce an apples-to-apples comparison, may include: Bi-directional power inverters, battery management software systems, additional MW and MWh capacity to avoid accelerated degradation from full range cycling, DC to AC power conversion losses, battery replacement over project life, etc.

hours (or to shift a solar installation's production into hours without system-wide overgeneration) under a 40% or 50% RPS scenario with significant quantities of solar PV resources. Moreover, if 3 hours of thermal storage did turn out to be the most economic size, the hypothetical solar thermal plant could reduce the size of its storage capability, making the costs lower than the 6-hour storage cited in Mr. Powers' cost comparison.

Q. If battery storage turns out to be more economical than molten salt-based thermal storage, is there any reason why the hypothetical solar thermal plant could not utilize battery storage instead of thermal storage?

A. No, if battery storage were cheaper than thermal storage there is no reason why a solar thermal plant could not utilize battery storage in the same way that a PV facility could. This is in contrast to a PV facility, which could not effectively make use of molten salt storage. However, indications today are that thermal storage is less expensive than battery storage. Mr. Powers estimates that the cost of six hours of thermal storage is $2,250/kW ($7,750 - $5,500)[18], significantly less than his estimate of $3,000/kW for six hours of battery storage.

Section V. Conclusion

Q. What is Mr. Powers' conclusion?

A. Mr. Powers' conclusion is that that the Commission should deny PSH's application to construct the Palen Solar Electric Generating Station (PSEGS) because "there are better, feasible alternatives" including distributed PV (p. 11).

Q. Does Mr. Powers propose a specific site for a sufficient quantity of DPV resources to displace the 500 MW PSEGS?

A. No, he does not. Instead, he asks the CEC to find that DPV is a superior alternative based on the sole criterion that it is distributed, even though its construction is not under control of the IOUs or PSH.

[18] Both cost estimates from Powers, p. 10

Q. Is it logical for the Commission to reject a specific project in favor of a hypothetical, non-specific alternative such as distributed PV potential?

A. No, it is not. If the Commission finds that PSEGS is not needed because there is the hypothetical potential for customers to build DPV somewhere in California, then it will be unable to approve the applications of any central station renewable generation in the foreseeable future. Opponents of the next central station renewable generation will use the same argument about the same 500 MW of DPV potential. The same 500 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. Has this Commission previously considered a DPV alternative in a solar power tower siting case?

A. Yes, in 2010 the Commission considered a DPV alternative to the Ivanpah Solar Electric Generating Station (ISEGS). The Commission concluded in that case that deploying sufficient DPV to meet the RPS standard would be challenging, and that DPV therefore "must be viewed as a partner, not a competitor or replacement for utility scale solar."[19] I agreed with the Commission's conclusions in that case, and I believe they are equally applicable to PSEGS.

Q. Does this conclude your testimony?

A. Yes, it does.

[19] (http://www.energy.ca.gov/2010publications/CEC-800-2010-004/CEC-800-2010-004-CMF.PDF, Alternatives, p. 17).

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Partner 2008 – Present
Senior Consultant 2002-2008

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 led the technical analysis and drafting of the recent report *Investigating a Higher Renewable Portfolio Standard for California*, prepared for the five largest utilities in California. He led a multi-company team that developed the Renewable Energy Flexibility (REFLEX) Model, a new stochastic production simulation model that calculates the need for power system flexibility under high renewable penetration, which was used for the California utility report as well as for separate renewable integration analysis performed on behalf of the California ISO. He has led numerous other resource planning studies on behalf of utilities, government agencies and electricity consumers, including studies of a 33% RPS for the California Public Utilities Commission and multiple studies of the economic benefits of long-line transmission projects. In 2007, he served as advisor, facilitator and drafter to the Idaho Legislature in developing the 2007 Idaho Energy Plan, the state of Idaho's first comprehensive, statewide energy plan in 25 years. His clients include the California Independent System Operator, California Public Utilities Commission, Colorado Public Utilities Commission, the Western Electric Coordinating Council, the Western Electric Industry Leaders' Group, the Western Interstate Energy Board, the City of Seattle, Pacific Northwest Generating Cooperative, Mid-American, AltaLink, Pacific Gas & Electric Company, Southern California Edison Company, the Sacramento Municipal Utilities District, the Bonneville Power Administration, TransElect, BC Hydro, and Hydro-Quebec TransEnergie.

Resource Planning and Valuation:

- Currently leading a team that is assessing electricity-natural gas infrastructure issues on behalf of the Western Interstate Energy Board.
- Currently leading a team that is investigating the capacity contribution of new wind, solar and demand response (DR) resources on behalf of the Sacramento Municipal Utilities District.
- Assisted the Colorado Public Utilities Commission in developing long-term scenarios to use across a range of energy infrastructure planning dockets.
- Assisted BC Hydro in evaluating the impact of BC's provincial greenhouse gas reduction policies on future electric load as part of BC Hydro's 2011 Integrated Resource Plan.
- Provided expert testimony in front of the California Public Utilities Commission on rates and revenue requirements associated with several alternative portfolios of demand-side and supply-side resources, on behalf of Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric.
- Served 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.

- Prepared 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.
- Provided generation and transmission asset valuation services to a number of utility and independent developer clients.

Renewables and Emerging Technology:

- Led the technical analysis and drafting of the influential report *Investigating a Higher Renewable Portfolio Standard for California*. The report evaluated the operational challenges, costs and solutions for integrating a 40% or 50% Renewable Portfolio Standard on behalf of the five largest utilities in California.
- Led the team that developed the Renewable Energy Flexibility (REFLEX) model, commercial software that assesses power system flexibility needs under high renewable penetration.
- Led the team that developed the Renewable Energy Capacity Planning (RECAP) model, commercial software that calculates reliability metrics such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE) and Planning Reserve Margin (PRM), along with Effective Load-Carrying Capability (ELCC) of wind and solar resource, demand response programs, and other dispatch-limited resources.
- Currently advising the CPUC on renewable energy resource policy and procurement.
- Currently leading the California Independent System Operator's (CAISO) renewable integration needs studies. The studies are evaluating the need for firming capacity and flexible resources to accommodate the variable and unpredictable nature of wind and solar generation. Results of the studies will be used to determine the need to procure new, flexible resources.
- Led the team that developed renewable and conventional resource cost and performance characteristics for use in the WECC's Regional Transmission Expansion Planning process.
- On behalf of the Wyoming Governor's Office, developed a model of the cost of developing wind resources in Wyoming relative to neighboring states to inform policy debate regarding taxation. The model included detailed representations of state-specific taxes and capacity factors.
- 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.
- Evaluated market opportunities and provided strategic advice for renewable energy developers 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.

Transmission Planning and Pricing:

- Currently serving as technical support to the Western Electric Coordinating Council's Scenario Planning Steering Group (SPSG). The SPSG is developing scenarios for long-term transmission planning in the Western Interconnection.
- Currently advising several transmission developers seeking approval for projects through the CAISO's Transmission Planning Process.
- Led a team that investigated the use of Production Cost Modeling for the purpose of allocating costs of new transmission facilities on behalf of the Northern Tier Transmission Group, and contributed to NTTG's Order 1000 compliance filing.
- Served as an expert witness in front of the Alberta Utilities Commission in a case regarding the Alberta Electric System Operator's proposed methodology for allocating Available Transmission Capacity among interties during times of congestion.
- Led studies in 2009, 2011 and 2012 to develop generation and transmission capital cost assumptions for use in WECC's Transmission Expansion Planning and Policy Committee (TEPPC) studies.
- Contributed to a study of the benefits of North-South transmission expansion in Alberta on behalf of AltaLink.
- Led a study for WECC to estimate the benefits of developing a centralized Energy Imbalance Market (EIM) across the Western Interconnection. The study estimated benefits due to increased generation dispatch efficiency resulting from reduced market barriers and increased load and resource diversity among western Balancing Authorities. Led several follow-up studies of alternative Western EIM footprints for potential EIM participants.
- 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 regions.
- 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 Council when it seeks approval for large distribution or transmission projects.
- Conducted screening studies of long-distance transmission lines connecting to remote renewable energy zones for multiple western utilities.
- 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.
- Assisted British Columbia Transmission Corporation and Hydro-Quebec TransEnergie with open access transmission tariff design.
- Represented BC Hydro in RTO West market design process in areas of congestion management, ancillary services, and transmission pricing.

Energy and Climate Policy:

- Developed policy themes and integrated them into the four long-term planning scenarios under consideration by WECC's Scenario Planning Steering Group.
- Led a team that developed a model of deep carbon dioxide emissions reductions scenarios in the western United States and Canada on behalf of the State-Provincial Steering Committee, a body of western state and provincial officials that provides oversight for WECC.
- Led a study of likely changes to power flows and market prices at western electricity trading hubs following California's adoption of a cap-and-trade system for regulating greenhouse gas emissions in 2013.
- 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 CORPORATION 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 Rueil-Malmaison, France
M.S., International Energy Management & Policy

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

Citizenship

United States

Expert Witness Testimony

1. *California Energy Commission, 2013, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

2. *Alberta Electric Utilities Commission, 2012, testified on behalf of Powerex Corporation reviewing industry practices regarding treatment of existing transmission capacity, in the case when new transmission lines are interconnected.*

3. *California Public Utilities Commission, 2011, provided testimony on behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company regarding cost, revenue requirement, average retail rates, and cost of carbon reductions from alternative resource portfolios in the Long-Term Procurement Planning Proceeding.*

4. *California Energy Commission, 2010, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

Selected Public Presentations

1. *"Meeting the Demands of Renewables Integration—New Needs, New Technologies, Emerging Opportunities", invited panelist, InfoCast 2nd Annual California Energy Summit, San Francisco, California, May 28, 2014*

2. *"Power System Flexibility Needs under High Renewables", EUCI Utility Resource Planning Conference, Chicago, Illinois, May 14, 2014*

3. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Western Interstate Energy Board Annual Meeting, Denver, Colorado, April 24, 2014*

4. *"Power System Flexibility Needs under High RPS", Joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 26, 2014*

5. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 25, 2014*

6. *"Investigating a Higher Renewables Portfolio Standard for California", 19th Annual Power Conference on Energy Research and Policy, University of California Energy Institute, Berkeley, California, March 17, 2014*

7. *"Investigating a 50 Percent Renewables Portfolio Standard in California", Northwest Power and Conservation Council, Portland, Oregon, March 12, 2014*

8. *"Investigating a 50 Percent Renewables Portfolio Standard in California", Western Systems Power Pool, Spring Operating Committee Meeting, Whistler, B.C., March 5, 2014*

9. *"Investigating a Higher Renewables Portfolio Standard for California", Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Salt Lake City, Utah, February 25, 2014*

10. *"Investigating a 50 Percent Renewables Portfolio Standard in California", Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Webinar, February 12, 2014*

11. *"Flexibility Planning: Lessons From E3's REFLEX Model", EUCI Conference on Fast Ramp and Intra-Hour Market Incentives, San Francisco, California, January 29-30, 2014*

12. *"The Effect of High Renewable Penetration on California Markets and Carbon Balance", EUCI Conference on California Carbon Policy Impacts on Western Power Markets, January 27-28, San Francisco, California, 2014*

13. *"Reliance on Renewables: A California Perspective", invited panelist at Harvard Electricity Policy Group, Seventy-Third Plenary Session, Tucson, Arizona, December 13, 2013*

14. *“The Role of Renewables in Meeting Long-Term Greenhouse Gas Reduction Goals”, State Bar Of California, Energy And Climate Change Conference, Berkeley, California, November 14, 2013*

15. *“Benefits, Costs and Cost Shifts from Net Energy Metering”, invited expert panelist at Washington Utilities and Transportation Commission Workshop on Distributed Generation, Olympia, Washington, November 13, 2013*

16. *Pacific Northwest Utilities Conference Committee (PNUCC) California Power Industry Roundtable, invited panelist, Portland, Oregon, September 6, 2013*

17. *“After 2020: Prospects for Higher RPS Levels in California”, invited speaker at Northwest Power and Conservation Council’s California Power Markets Symposium, Portland, Oregon, September 5, 2013*

18. *“Determining Flexible Capacity Needs for the CAISO Area”, invited speaker at Northwest Power and Conservation Council’s California Power Markets Symposium, Portland, Oregon, September 5, 2013*

19. *“California Climate Policy and the Western Energy System”, invited speaker at the Western Interstate Energy Board annual meeting, Reno, Nevada, June 13, 2013*

20. *“Determining Power System Flexibility Need”, EUCI Conference on Resource Planning and Asset Valuation, Westminster, Colorado, May 21, 2013*

21. *“California Policy Landscape and Impact on Electricity Markets”, EUCI Conference on Resource Planning and Asset Valuation, Westminster, Colorado, May 21, 2013*

22. *“Determining Power System Flexibility Need”, EUCI Conference on Fast and Flexi-ramp Resources, Chicago, Illinois, April 23, 2013*

23. *“State-Provincial Steering Committee WECC Low Carbon Scenarios Tool”, 3 Interconnections Meeting, Washington, DC, February 6, 2013*

24. *“Distributed Generation Benefits and Planning Challenges”, Committee on Regional Electric Power Cooperation/State-Provincial Steering Committee, Resource Planners’ Forum, San Diego, California, October 3, 2012*

25. *“Thoughts on the Flexibility Procurement Modeling Challenge”, California Public Utilities Commission, Long-Term Procurement Planning Workshop, San Francisco, California, September 19, 2012*

26. *“Generation Capital Cost Recommendations for WECC 10- and 20-Year Studies”, Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Technical Advisory Subcommittee, Webinar, August 15, 2012*

27. *“Renewable Energy Benefits”, California Energy Commission, Integrated Energy Policy Report Workshop, Sacramento, California, April 12, 2012*

28. *"The Role of Policy in WECC Scenario Planning", Western Electric Coordinating Council, Scenario Planning Steering Group, San Diego, CA, November 1, 2011*

29. *"WECC Energy Imbalance Market Benefit Study", Western Electric Coordinating Council, Board of Directors, Scottsdale, Arizona, June 22, 2011*

30. *"Renewable Portfolio Standard Model Methodology and Draft Results", California Public Utilities Commission Workshop, San Francisco, California, June 17, 2010*

31. *"Draft Results from 33% Renewable Energy Standard Economic Modeling", California Air Resources Board Workshop, Sacramento, California, May 20, 2010*

32. *"Market Opportunities for IPPs in the WECC", invited speaker at the Independent Power Producers of British Columbia Annual Meeting, Vancouver, British Columbia, November 2, 2009*

33. *"A Low-Transmission Alternative for Meeting California's 33% RPS Target", EUCI Webinar, July 31, 2009*

34. *"Remote Renewable and Low-Carbon Resource Options for the Pacific Northwest", Center for Research on Regulated Industries Conference, Monterey, California, June 19, 2009*

35. *"Engineers are from Mars, Policy-Makers are from Venus: The Effect of Policy on Long-Term Transmission Planning", invited speaker at the Western Electric Coordinating Council Long Term Transmission Planning Seminar, Phoenix, Arizona, February 2, 2009*

36. *"The Long-Term Path to a Stable Climate, and its Implications for BPA", invited speaker at the Bonneville Power Administration Managers' Retreat, Portland, Oregon, April 29, 2008*

37. *"Load-Resource Balance in the Western Interconnection: Towards 2020", Western Electric Industry Leaders Group, Las Vegas, Nevada, January 18, 2008*

38. *"Integrated Resource Planning for BPA Customers", invited speaker at the Bonneville Power Administration Allocation Conference, Portland, Oregon, September 19, 2006*

39. *"Idaho's Current Energy Picture", Energy, Environment and Technology Interim Committee, Boise, Idaho, July 11, 2006*

40. *"Locational Marginal Pricing – The Very Basics", Committee on Regional Electric Power Cooperation, San Diego, California, April 30, 2002*

41. *"Effect of 2000-2001 Energy Crisis on Washington's Economy", Conference on Business Economics, Seattle, Washington, July 19, 2001*

Refereed Papers

1. *C.K. Woo, T. Hob, J. Zarnikau, A. Olson, R. Jones, M. Chaitf I. Horowitz, J. Wang, "Electricity-market price and nuclear power plant shutdown: Evidence from California", Energy Policy, forthcoming*

2. *Woo, C.K., Zarnikau J, Kadish J, Horowitz I, Wang J, Olson A. (2013) "The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest," IEEE Transactions on Power Systems, 28(4), 4245-4253.*

3. *Olson A., R. Jones (2012) "Chasing Grid Parity: Understanding the Dynamic Value of Renewable Energy," Electricity Journal, 25:3, 17-27.*

4. *Woo, C.K., H. Liu, F. Kahrl, N. Schlag, J. Moore and A. Olson (2012) "Assessing the economic value of transmission in Alberta's restructured electricity market," Electricity Journal, 25(3): 68-80.*

5. *DeBenedictis, A., D. Miller, J. Moore, A. Olson, C.K. Woo (2011) "How Big is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest," Electricity Journal, 24:3, 72-76.*

6. *Woo, C.K., I. Horowitz, A. Olson, A. DeBenedictis, D. Miller and J. Moore (2011) "Cross-Hedging and Forward-Contract Pricing of Electricity in the Pacific Northwest," Managerial and Decision Economics, 32, 265-279.*

7. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

8. *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, 22:9, 38-46.*

9. *Moore, J., C.K. Woo, B. Horii, S. Price, A. Olson (2009) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

10. *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.*

11. *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.*

12. *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.*

13. *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.*

14. *Woo, C.K., A. Olson and I. Horowitz (2006) "Market Efficiency, Cross Hedging and Price Forecasts: California's Natural-Gas Markets," Energy, 31, 1290-1304.*

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

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

Research Reports

1. *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric Sector Perspective, March 2014, project lead and contributing author,* *https://ethree.com/public_projects/wieb.php*

2. *Investigating a Higher Renewables Portfolio Standard for California, January 2014, technical lead and lead author, http://www.ethree.com/public_projects/renewables_portfolio_standard.php*

3. *Optimal Investment in Power System Flexibility, E3 White Paper, December 2013, https://ethree.com/documents/Olson_Flexibility_Investment_2013-12-23.pdf*

4. *Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process, October 2012, editor and contributor, http://www.wecc.biz/committees/BOD/TEPPC/TAS/121012/Lists/Minutes/1/121005_GenCapCostReport_finaldraft.pdf.*

5. *Economic Assessment of North/South Transmission Capacity Expansion in Alberta, January 2012, contributor.*

6. *WECC EDT, Phase 2 EIM Benefits, Analysis & Results, October 2011, contributor, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf*

7. *High Plains Express Initiative, Stage 2 Feasibility Report, April 2011, contributor, http://www.highplainsexpress.com/site/stakeholderMeetingDocuments/HPX_Stage-2_Feasibility-report.pdf*

8. *State of Wyoming Wind Energy Costing Model, June 2010, author, http://legisweb.state.wy.us/2010/WyomingWindModel_7_01_2010.pdf*

9. *Recommendations for Documentation of Seattle City Light Energy Delivery Capital Expenditures, February 2010, contributor, http://clerk.seattle.gov/~ordpics/31219exA.pdf*

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

http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

11. *California Public Utilities Commission, Energy Division Straw Proposal on LTPP Planning Standards, June 2009, contributor, http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf*

12. *California Public Utilities Commission, Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California, September 2008, http://www.cpuc.ca.gov/NR/rdonlyres/029611EA-D7C7-4ACC-84D6-D6BA8515723A/0/ConsultantsReportonUtilityPlanningPracticesandAppendices09172008.pdf.*

13. *Remote Renewable and Low-Carbon Resource Options for BPA, May 2008, author, http://www.ethree.com/public_projects/BPA_options.html*

14. *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*

15. *Umatilla Electric Cooperative 2008 Integrated Resource Plan, January 2009, author.*

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16. *Lower Valley Energy 2007 Integrated Resource Plan Update, February 2007, author.*

17. *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*

18. *Base Case Integrated Resource Plan for PNGC Power, April 2006, author.*

19. *Integrated Resource Planning for Coos-Curry Electric Cooperative, August 2005, author.*

20. *Integrated Resource Planning for Lower Valley Energy, December 2004, author.*

21. *"A Forecast Of Cost Effectiveness: Avoided Costs and Externality Adders", prepared for the California Public Utilities Commission, February 2004, contributor.*

22. *Stepped Rate Design Report, prepared for BC Hydro and filed with the BCUC, May 2003, contributor.*

23. *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*

24. *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*

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

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

27. *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*

28. *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*

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

30. *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.*