BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 13A-836E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2014 RENEWABLE ENERGY STANDARD COMPLIANCE PLAN

ANSWER TESTIMONY OF RICK GILLIAM

ON BEHALF OF THE VOTE SOLAR INITIATIVE

(Hearing Exhibit 1100)

December 2, 2013

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1. Introduction

Q. Please state your name and business address.

A. My name is Rick Gilliam. My business address is 1120 Pearl Street, Suite 200, in Boulder, Colorado.

Q. On whose behalf are you submitting this pre-filed direct testimony?

A. This testimony is submitted on behalf of the Vote Solar Initiative (Vote Solar).

Q. By whom are you employed and in what capacity?

A. I serve as Director of Research and Analysis for Vote Solar, and oversee policy initiatives, development and implementation. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. We have over 2,000 members in Colorado.

Q. Please describe your educational background.

A. I have a Masters Degree in Environmental Policy and Management from the University of Denver, Denver, Colorado. I also have Bachelor of Science Degree in Electrical Engineering from Rensselaer Polytechnic Institute in Troy, New York.

Q. Please describe your experience in utility regulatory matters.

A. Prior to joining Vote Solar in January of 2012, my regulatory experience included five (5) years in the Government Affairs group at Sun Edison, one of the world's largest solar developers, as a manager, director and eventually vice president; twelve (12) years with Western Resource Advocates (formerly known as the Land and Water Fund of the Rockies) as Senior Policy Advisor; and twelve (12) years in the Public Service Company of Colorado (PSCo or the Company) rate division as Director of Revenue Requirements. Prior to that, I spent six (6) years with the Federal Energy Regulatory Commission as a technical witness (engineer). All told, I have in excess of thirty years experience in utility regulatory matters. A summary of my background is appended as Attachment A.

Q. Have you previously testified before the Colorado Public Utilities Commission ("PUC" or "Commission")?

A. Yes, I have.

Q. Before what other utility regulatory commissions have you testified?

A. I have testified in proceedings before the Arizona Corporation Commission, Idaho Public Utilities Commission, Nevada Public Utilities Commission, the New Mexico Public Regulation Commission, the Utah Public Service Commission, the Wyoming Public Service Commission, and the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address the "net metering incentive" proposal as derived and set forth by the Company in its submittal, and its request to charge solar customers for production meters.

Q. Will you summarize your findings and recommendations?

A. Yes. At the outset, I want to say that this litigated process is unlikely to produce a thorough review and vetting of the issues underlying the Company's proposal. There are simply too many structural and temporal limitations for this process to thoroughly evaluate the calculation of the net costs and benefits of distributed solar generation or "DSG." Vote Solar supports a thorough unbiased review of the net costs and benefits of DSG on the utility system, and has participated in cost/benefit review processes around the country. However, the limitations of this litigated proceeding prevent a fully informed outcome.

The underlying analytical basis of the Company's proposed "net metering incentive" is a flawed study performed by the Company, which undervalues DSG. Coupled with a general lack of applicable DSG data, analytical errors in determination of revenue loss, and other matters, Vote Solar recommends that the "net metering incentive" be rejected in its entirety. Instead, the Commission should establish and lead a series of open workshops to review and evaluate all of the components of value generated by DSG and the costs incurred by the Company. The goal of the workshops would be to formulate a standardized methodology for valuing DSG that could be used in subsequent proceedings.

2. Background and Context

Q. Please briefly provide relevant background information.

A. The genesis of this issue in Colorado begins in 2004 with a citizen approved ballot initiative – Amendment 37 (A37). A37 began with a declaration of intent[1] as follows:

> *Energy is critically important to Colorado's welfare and development, and its use has a profound impact on the economy and environment. Growth of the state's population and economic base will continue to create a need for new energy resources, and Colorado's renewable energy resources are currently underutilized.*
>
> *Therefore, in order to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state, it is in the best interests of the citizens of Colorado to develop and utilize renewable energy resources to the maximum practicable extent.*

Thus the voters adopted A37 with the declared intent of capturing seven benefits:

1. *To save consumers and businesses money,*
2. *Attract new businesses and jobs,*
3. *Promote development of rural economies,*
4. *Minimize water use for electricity generation,*
5. *Diversify Colorado's energy resources,*
6. *Reduce the impact of volatile fuel prices, and*
7. *Improve the natural environment of the state*

These benefits need to be taken into account when looking at the implementation of the Renewable Energy Standard and its subparts.

Q. Are there specific elements of A37 you would like to highlight?

[1] This declaration of intent is referenced in the Renewable Energy Standard Statute CRS 40-2-124, and the Commission Rule CCR 723-3-3651.

A. Yes. One of the core components of A37 was the inclusion and treatment of customer-sited solar generation. The net metering language has remained virtually unchanged since passage by the voters of Colorado in 2004, providing for (1) offset of the customer's own consumption, (2) monthly carryover of excess generation to the following month's consumption, and (3) compensation for annual net excess carryovers.

The rules implementing net metering by the Commission provide additional detail. Commission Rule 4 CCR 723-3664(b) describes the basic net metering requirements:

> If a customer with retail renewable distributed generation generates renewable energy pursuant to paragraph 3664(a) in excess of the customer's consumption, the excess kilowatt-hours shall be carried forward from month to month and credited at a ratio of 1:1 against the customer's retail kilowatt-hour consumption in subsequent months. Within 60 days of the end of each calendar year, or within 60 days of when the customer terminates its retail service, the investor owned QRU shall compensate the customer for any accrued excess kilowatt-hour credits, at the investor owned QRU's average hourly incremental cost of electricity supply over the most recent calendar year. However, the customer may make a one-time election, in writing, on or before the end of a calendar year, to request that the excess kilowatt hours be rolled over as a credit from month to month indefinitely until the customer terminates service with the investor owned QRU, at which time no payment shall be required from the investor owned QRU for any remaining excess kilowatt hour credits supplied by the customer.

Q. Is it your view that the Company has implemented the statutory provisions or the rules of the Commission properly?

A. Absolutely. Indeed, I believe the Company has performed in an exemplary fashion implementing the net metering rules. I have frequently used Xcel's program as an example of how to properly implement net metering policies.

Q. Please provide any additional context and background information relevant to the Company's proposal in this proceeding.

A. The core issue for Vote Solar in this proceeding is the so-called "net metering incentive" proposed by the Company. To a large extent, this significant change in accounting is based upon a study undertaken by the Company several years ago ("DSG Study," submitted here as Exhibit KLS-1). The genesis of this study began over 4.5 years ago. On May 1, 2009, Xcel filed rate case testimony and exhibits with the Commission, seeking to set new rates for electric customers (i.e., a rate case). On August 4, 2009, PSCo withdrew certain sections of its rate case dealing with a Transmission and Distribution Capacity Charge it sought to assess on net-metered residential and small commercial customers with solar photovoltaic (PV) system installations. PSCo stated that issues related to the recovery of transmission and distribution charges would be better addressed through a stakeholder process outside of a rate case.

The Commission allowed PSCo to withdraw those sections of the advice letter and testimony related to the proposed Transmission and Distribution Capacity Charge, and found that a cost and benefit study of DSG on the Public Service system would be a worthwhile and an important tool in evaluating the impact of the resource. At a Commissioner's Information Meeting held on August 18, 2010, PSCo and the Governor's Energy Office (GEO, now the "Colorado Energy Office" or "CEO") presented an outline of a joint study methodology that would be conducted based on avoided/incremental cost principles. Following the information meeting, the Commission indicated that it was satisfied with the proposed scope and directed the parties to begin the Study.

Xcel formed a Technical Review Committee (TRC) to provide guidance to the study process. The TRC process was expected to result in a completed study by May of 2011. Below is a summary of the originally proposed dates in the Study plan, and a record of actual meetings:

TABLE 1: DSG STUDY OUTLINE

Action Item	Study Plan	Actual
Presentation of Scope & Study Methodology to TRC	Sep 8, 2010	Oct 6, 2010
TRC Meeting 2: Progress to Date[2]	---	Apr 27, 2011
TRC Meeting 3	---	Jun 16, 2011
TRC Meeting 4	---	Aug 17, 2011
TRC Meeting 5	---	Dec 12, 2011
TRC Meeting 6	---	Dec 19, 2011
Presentation of Draft Report to TRC	Apr 24, 2011	Apr 1, 2013
Presentation of Final Study to PUC	May 15, 2011	May 23, 2013

Note that there was a 15-month gap between the 6th TRC meeting, at which point only a modest amount of Study progress had been made, and the issuance of a draft report in April of this year. Following electronic receipt of the draft report from PSCo, TRC members were in the process of responding to the accompanying request to find a time for the next TRC meeting to discuss the draft Study, when the Company abruptly filed the Study, unchanged from the draft as far as we know,[3] with the Commission on May 23, 2013 into Docket No. 11M-426E (the "M docket"). Thus, there was no opportunity to provide feedback on the April 1 draft Study prior to submittal to the Commission.

[2] Note: at this time, PSCo was still targeting late May 2011 for completion.
[3] In response to VSI2-9, the Company seems to indicate it does not have a copy of the April 1 study report and can't confirm whether it is the same study or not.

Subsequent to the Company's submittal in the M docket, the Commission issued Decision No. C13-0764-I addressing the submittal of the report noting among other things:

> *4. The Commission has been anticipating the Report since May 2011, its original proposed completion date. We are also aware of the significant interest from a broad range of stakeholders in the Report and its findings.*
>
> *5. We therefore find good cause to solicit comments on the Company's Report. Commenters are asked to provide feedback on the strengths and weaknesses of the study and its findings and may also offer suggestions for steps that the Commission might take after receiving comments on the Report.*

In response, Vote Solar, along with the Solar Energy Industries Association (SEIA) and the Colorado Solar Energy Industries Association (COSEIA), jointly submitted some 60 pages of comments on the PSCo Report outlining our concerns, questions, areas requiring further development, updating or understanding, and so forth, on September 9. Other parties submitted comments in the M docket as well.

However, in the intervening period on July 24, the Company submitted its 2014 Renewable Energy Standard Compliance Plan utilizing ostensibly the same DSG Study submitted in the M docket as the basis for a completely new proposal related to net metering and the Renewable Energy Standard Adjustment (RESA) account. It should be noted that the Company at no time sought to contact any members of Vote Solar, nor to my knowledge COSEIA, SEIA, the Interstate Renewable Energy Council (IREC), The Alliance for Solar Choice (TASC), or any other party representing solar interests to start a dialogue prior to initiating this complex new issue in a new proceeding, despite multiple requests for meetings over the past 12 months from Vote Solar to do so.

Q. Why did the Company submit the Study in the M docket?

A. The Company submitted the Study to the M docket for what I believe to be a very good reason, according to Company witness Kent Scholl:[4]

> On October 29, 2009, the Commission found that a report on the costs and benefits of distributed solar generation (DSG) systems would be worthwhile and an important tool in evaluating the impact of DSG, particularly on Public Service's system. (Decision No. C09-1223.) On May 24, 2011, the Commission opened a miscellaneous docket (No. 11M-426E) for the purpose of gathering research pertaining to current and historical solar photovoltaic incentive practices. (Decision No. C11-0549.) It is my understanding that the Research and Energy Issues Section had suggested that the study, which had been approved by the Commission in Docket No. 09AL-299E (by approving the settlement), would be appropriately filed in the miscellaneous docket and the Company determined that to file the DSG Study in the miscellaneous docket was consistent with the purpose of the docket. As it stated in its notice of filing in Docket No. 11M-426E, moreover, the Company filed the DSG Study <u>in order to give the Commission the opportunity to solicit comments on the DSG Study in that proceeding, not only from TRC members but from all other interested stakeholders, so that the Commission could take those comments into account when considering the DSG Study</u>. (emphasis added)

Q. What happened to the M docket?

A. By Decision No. C13-1258, the Commission closed the M docket with virtually no discussion, other than noting that Public Service's study is presently at issue in an adjudicated proceeding, and finding that the purpose of the M docket had been fulfilled.

Q. Will the Commission be able to solicit comments on the DSG Study "from all other interested stakeholders" in this proceeding?

A. No. In addition to closing the M docket in which informal discussions among all interested stakeholders could have taken place, the Commission then excluded a number of parties from full participation in this proceeding. This shift from the

[4] Response to VSI2-1

traditional inclusive nature of the Commission to more exclusive representation of specific interests is troubling.

Q. Please provide Vote Solar's perspective on the procedure for resolving the issues the Company is raising.

A. Vote Solar team members participated in good faith during the DSG Study process, and with knowledge gained from experience with net metering related issues in other states, was aware that the DSG Study would be highly complex and controversial, and thus sought to meet with the Company on numerous occasions to discuss the potential for common ground outside of, and prior to, litigation. The Company however chose to "initiate a dialogue" in just such a formal litigated proceeding. Litigated proceedings by their nature are adversarial and thus are a very poor forum for a dialogue. This process is too brief and too formal to reach accommodation prior to formal hearings. Indeed, in this proceeding, discovery is the only form of "dialogue" and given the Company's delayed responses (and no responses to some questions) is a wholly inadequate way to discuss such complex issues. The following table outlines our experience with discovery in this proceeding:

TABLE 2: DISCOVERY DATA

Portion of discovery responses received late	82%
Portion of discovery received within 2 business days of testimony due date	14%
Number of discovery questions not answered	5
Portion of discovery to which Company objected	11%

There was, and continues to be, a lack of transparency and access to data for the TRC members, and now others, to be able to corroborate results or to present alternative views. The goal should be to elicit thorough and completely developed data and information so that the Commission may make a fully informed decision.

As a result of the Company's filing in this case, the Commission's decision to close the M docket, denial of interventions of other interested stakeholders, denial of our request to extricate the net metering issues including the DSG study from this docket, and denial of TASC's Motion to Strike, all avenues for informal review and resolution of these issues are closed and we are forced to respond to the new and untried "net metering incentive" proposal based on the partially-updated complex 100 page, three-year DSG Study in a very short time frame. Indeed, over two years has passed between the last TRC meeting and the hearing in this proceeding without any feedback or meaningful dialogue with stakeholders.

However, the Commission has the ability to establish a proper and conducive forum for addressing the costs and benefits of DSG. As summarized earlier in my testimony, the Commission should reject the "net metering incentive" proposal in this plan, and instead establish and lead a series of open workshops through a transparent review and evaluation of all of the components of value generated by DSG and the costs incurred by the Company. The outcome of the workshops should be a standardized methodology for valuing DSG.

3. The Effects of Net Metering

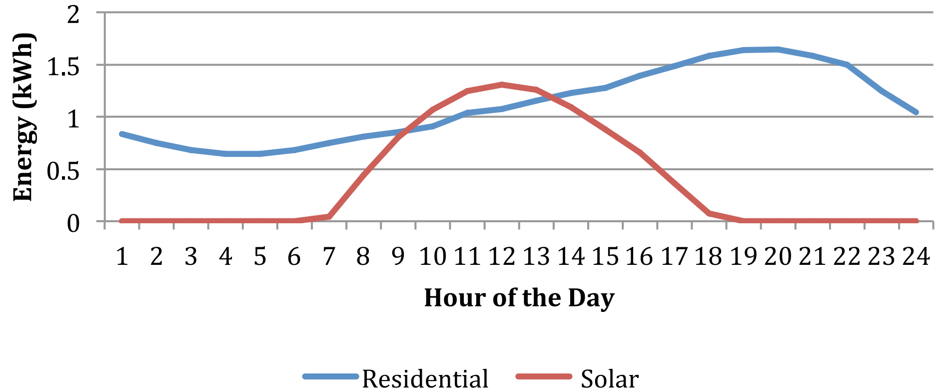
Q. What is your understanding of the Company's concerns?

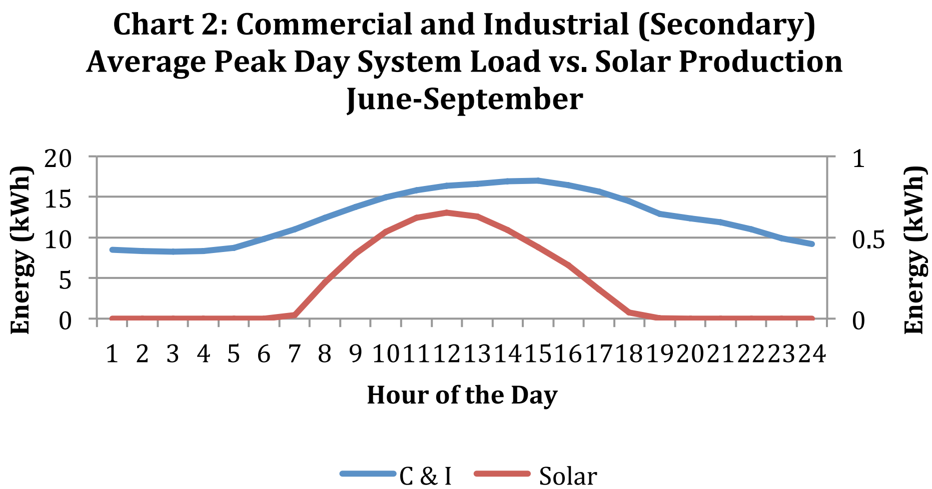
A. My understanding is that the Company believes that Colorado's net metering policy unfairly encourages retail customers to install DSG to generate and consume energy on-site in lieu of purchasing all its needs from PSCo.

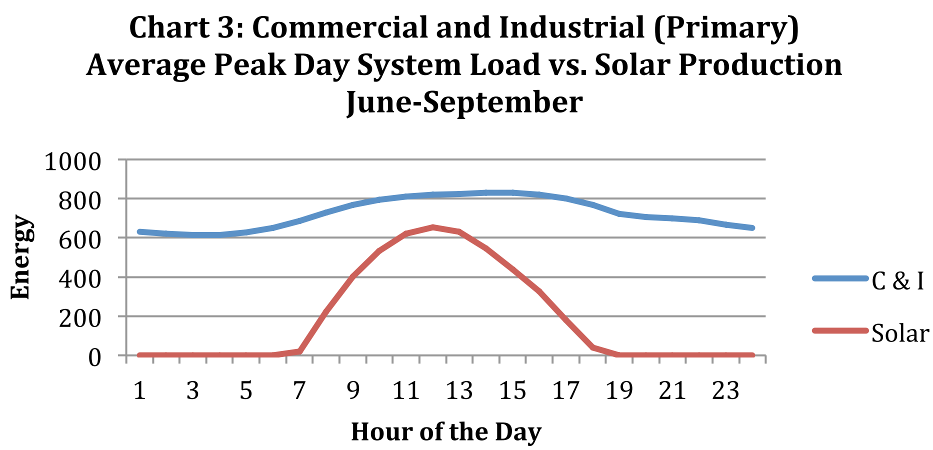
Q. What is net metering?

A. Net metering is a simple billing mechanism that credits solar system owners for any electricity exported onto the electricity grid. When a customer installs solar generation, there are two things that can happen: the solar generation can be either (1) less than, or (2) more than the host customer consumption. Under the first scenario, the customer consumes all solar generation, if any, instantaneously on-site, and the Company sees a reduction in sales to that customer, similar to the customer installing energy efficiency technologies. Under the second scenario, the solar customer consumption is less than the total solar generation and the excess power from his or her system is exported off-site. The following charts depict these situations graphically for residential and non-residential customers.

Chart 1: Residential Average Peak Day System Load vs. Solar Production June-September







Note that based on *typical* load shapes for these broad customer groupings (i.e. non-residential customer load being more highly correlated with solar generation profiles), residential customers would be more likely to export power off-site than are non-residential customers. Of course this depends entirely on the size of the customer and the size of the solar generator.

Q. What happens under the second scenario if energy is occasionally exported to the grid?

A. By the laws of physics, the electricity flowing off of a customer's site reduces the overall loading of the local distribution circuit thereby reducing losses for everyone, and flows into the nearest load sink – or point of consumption, usually a neighboring home or business. The Company has no operational control of the behind-the-meter generation outside of disconnecting them from the grid[5] and there is no operational cost to the Company. It should be noted that although the Company did not generate that power, nor ship the power across the Company's transmission grid or even beyond the local distribution circuit, the Company sells the exported power at full retail rates to the nearby customer receiving those electrons.

Q. What happens if there is not any exported energy?

A. If solar generation is never exported, then all of the solar generation is consumed on-site and the DSG is simply reducing the customer's consumption. The Company should have no more concern for that situation than it does for sales reductions that have been occurring for years for a variety of other reasons.

Q. Does the Company's concern about DSG extend to systems with no exports?

A. Yes. Even if all of the solar generation is consumed on-site and exports are zero, the Company claims there is still a "net metering incentive."[6] Under the Company's proposal, each and every kilowatthour generated by a DSG system would be multiplied by the proposed "net metering incentive" rate and added as 'expenditures' within the RESA account. This is remarkable to me as customer energy consumption within classes varies widely by its nature. The Company does not have the authority

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[5] See response to CPUC2-9(d).
[6] See response to VSI4-16.

to require its customers to use a minimum amount of electricity. Within certain physical bounds, customers are free to use as much or as little electricity as they like. The *means* of consumption reduction utilized by an individual customer should be irrelevant provided it doesn't compromise safety and reliability.

Q. Is DSG the primary cause for retail electric sales reductions?

A. No. Sales can be reduced for many reasons including local, regional or national economic conditions, customer implementation of conservation measures or energy efficiency technologies, effects of cooler summer weather, shrinking household size, and so forth. Conversely, sales can increase as a result of widespread adoption of new appliances such as widescreen TVs, increasing penetrations of Electric Vehicles (EVs), growing households, home-based businesses, robust economic conditions, etc.

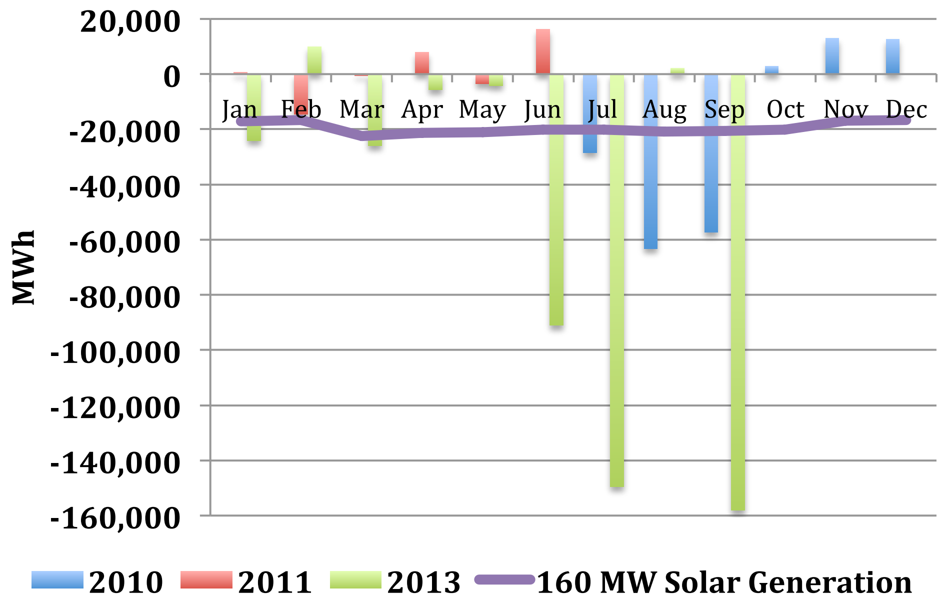
Weather is another factor affecting sales. The Company cites cooler weather as affecting earnings levels in its most recent SEC Form 10Q:

> ***PSCo*** — PSCo's ongoing earnings decreased $0.03 per share for the third quarter of 2013 and increased $0.02 per share for the nine months ended Sept. 30, 2013. Third quarter earnings declined as a result of lower electric margins and higher O&M expenses. Electric margins were impacted by cooler weather compared to prior year and accruals for potential customer refunds associated with the 2013 earnings test. These factors were partially offset by lower interest charges.

Indeed, weather can have significant impacts on sales from month to month. The following chart demonstrates the volatility of weather related effects on the Company's sales by month in comparison with the approximate total amount of solar energy generation (resulting from 160 MW):[7]

[7] Source data from response to VSI5-8

Chart 4: Monthly Weather Effects vs. All DSG



Additionally, the Company experienced declining retail electricity sales growth during the economic recession. While difficult to quantify specifically, the growth rate pre-recession (2004-2008) of 1.8% fell to nearly zero during the recession (2009-2012).[8]

[8] Response to VSI1-28.

Table 3: PSCO Weather Normalized Retail Sales (Calendar Month, MWh)			
Year	Weather Normalized Retail Sales	Annual Growth	Average Annual Growth
2004	26,209,213	1.8%	
2005	26,208,067	0.0%	
2006	26,763,477	2.1%	1.8%
2007	27,569,062	3.0%	
2008	28,081,521	1.9%	
2009	27,672,042	-1.5%	
2010	28,123,374	1.6%	0.1%
2011	28,142,524	0.1%	
2012	28,235,383	0.3%	

A reduction of 1.7% in sales can reduce revenue by about $45 million annually, far more than the effect of DSG on the utility.

Q. How are sales changes related to root causes other than DSG treated by the Company?

A. Energy efficiency and conservation measures provide a good example. Some such measures are installed by customers under the auspices and sometimes with financial encouragement from the Company. Others can be market-based such as adoption of energy efficient lighting. In response to VSI1-43, the Company described their tracking of revenue changes related to such technologies as follows:

> The revenue impacts of the sales reductions attributable to Company-sponsored energy-efficiency programs are treated the same way as comparable reductions in energy use attributable to non-utility energy-efficiency measures. In neither case

> is there an explicit, routine identification of the revenue reduction attributable to the energy-efficiency measures.

Q. How much solar generation can a net-metered retail customer install?

A. Under Colorado statute and rules, a customer can install a system that can generate up to 120% of the customer's usage.

Q. How many customers have these maximum-sized installed systems?

A. According to the Company's responses to Vote Solar's and other's discovery, it does not know.[9]

Q. How many customers have generation that exceeds their annual consumption?

A. According to the Company's responses to Vote Solar's and other's discovery, it does not know.[10]

Q. Does this lack of information about DSG customers concern you?

A. Yes. The Company seemingly has little idea how many, if any, of their solar net metered customers generate as much electricity with their own solar systems as they use on an annual basis. Yet, it makes that very assumption in its illustrative examples purportedly showing the degree of excess generation for the two customer classes with the smallest customers in Appendix IV to Exhibit KLS-1. The Commission should not make major policy decisions on the basis of illustrative examples that cannot be shown to represent reality.

Q. How much revenue has been lost by the utility in recent years due to DSG?

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[9] See response to VSI2-23 and 67, CPUC2-9 and WRA2-10.
[10] Ibid.

A. The Company does not know this either, according to the response to Commission Staff's discovery request 1-10. In addition, the Company doesn't have any studies demonstrating any actual shifting of costs.

Q. Does the Company have production meters on its customers with solar generation?

A. According to the Company's responses to Vote Solar's discovery, it has some production meters, but it doesn't know how many or where they are deployed.[11]

Q. How have changes to sales levels been handled historically in rate proceedings?

A. With limited exceptions, sales changes are "baked in" to the development of rates in a rate proceeding. Electricity rates are price signals and customers respond to those signals. Indeed, rates are designed to send signals to customers about how and sometimes when to modify their electricity consumption patterns.

The problem with the PSCo submittal is that it is singling out a sales change due to a particular action taken by a subset of its customers for special treatment. Such treatment is premature. The sales and load-reducing effects of retail customers' deployment of DSG changes not only sales, but also billing determinants, expenses, investments and cost allocations to customer classes in the next rate case.

4. The "Net Metering Incentive" Proposal

Q. Please describe the Company's proposal.

A. The Company is seeking to include a dollar amount representing its view of a "net metering incentive" in the RESA with an offsetting amount flowing through the ECA.

[11] See responses to VSI1-15, VSI4-3 and VSI4-55.

The "net metering incentive" purports to be the difference between benefits and costs of DSG and presumably could be either positive or negative (adding to, or reducing, the RESA balance).

Q. What actual costs would be added to the RESA under the PSCo proposal?

A. It is difficult to delineate the exact costs (e.g. the actual costs by FERC account) that would be added to the RESA due to the Company's method of computation, however the costs would be a subset of the utility costs embedded in rates such as net depreciated cost of production, transmission, distribution, and general assets, operation and maintenance costs, depreciation, taxes, and so forth. In other words, these are the costs that have been incurred by the utility to provide electric service over the past 60 years or so.

Q. Are these costs identified in Commission Rule 3661 as allowable for recovery through the RESA?

A. No. None of the items listed in Rule 3661(c) resemble in any way historic costs embedded in rates. While the list in Rule 3661(c) is not all-inclusive, the language of the rule plainly states that the "net retail rate impact shall include the prudently incurred direct and indirect costs of all actions by a QRU to meet the renewable energy standard, …" Costs incurred over the last 60 years to provide electric utility service do not meet this standard as they were not incurred <u>to meet the renewable energy standard</u>.

Q. Please explain your issues with the Company's proposal to calculate a "net metering incentive."

A. The Company's proposal to calculate a "net metering incentive" is a solution in search of a problem. The analysis the Company is presenting to prove that a problem exists of sufficient magnitude to warrant the proposed near-term policy and accounting changes has not been validated. We believe that the evidence presented in this proceeding will demonstrate the inaccuracies and shortcomings of the Company's analysis.

Second, the Company's proposed "net metering incentive" accounting proposal has no effect on the Company's revenue or earnings, nor on anyone's rates, regardless of whether they have on-site DSG or not. Additionally, there is no effect of the present or anticipated penetrations of DSG on the Company's operations, nor have any studies been performed which show future impacts.

Third, the Company is discriminating against a subset of its customers.

Fourth, the Company does not have sufficient data and information about its solar customers and their DSG systems to make a revenue loss determination. Further, the Company has not performed appropriate analyses to determine if a problem exists, its magnitude, and potential solutions.

Q. What problem is the Company attempting to solve in its proposed "net metering incentive?"

A. The Company's concerns appear to be centered around its customers' ability to deploy DSG at a price at or below its retail rates. It suggests that the 23 systems applying for net metering "without incentives" is proof that net metering is itself an incentive.[12] This is illogical. The Company seems to not believe it is impossible for an alternative resource to generate electricity at a cost less than the retail rate.

In the unregulated world, the retail electricity rate simply becomes the price to beat spurring innovation, creative pricing options, and leases and other third party arrangements as competitive alternatives. Because the price of solar is, or will be, competitive with the price of grid electricity is not proof that the grid electricity rates are incorrect price signals. Innovation and customer choice should not be stifled because competitive alternatives may become lower cost than electricity supplied by the grid. Indeed, Xcel's mission is to *"provide our customers the safe, clean, reliable energy services they want and value at a* <u>*competitive*</u> *price."*(emphasis added) The *competitive* price offered by the Company is for an energy service for which it strives "to have prices in line with our peers, inflationary trends, or choices available to our customers, consistent with the relative value of those services."[13]

Q. Does the Company believe it competes with alternate providers of energy services?

A. No.[14]

Q. Does Vote Solar believe the Company competes with alternate providers?

A. Yes. The interest in customer-sited solar generation is proof that a portion of the Company's customers want and value energy services exhibiting a different set of

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[12] Direct Testimony of Karen Hyde, page 15, beginning generally on line 5. Note that the Company rejected these applications, but subsequently provided the 23 customers with incentives under the Solar*Rewards program.
[13] Response to VSI5-12.
[14] Response to VSI5-7.

characteristics more highly than the uniform PSCo offering, and such should be allowed without undue burden.

Q. Does the "net metering incentive" address a Company revenue or earnings shortfall?

A. No. According to the Company, the proposal has no impact on revenue or earnings and is revenue neutral.[15]

> "Debiting the RESA account and crediting the ECA account for a net metering incentive would have no impact on earnings. This process would shift the recovery of the net metering incentive amount from the ECA recovery mechanism, into the RESA recovery mechanism, but the overall amount of cost recovery would be the same."[16]

Q. Does the "net metering incentive" change the revenue collected from customers?

A. The Company noted that its recommendation does "not directly charge additional costs to existing Solar*Rewards customers nor new Solar*Rewards customers under the 2014 RES Plan."[17] Further follow-up revealed "no material increase or decrease in aggregate" for the bills paid by non-solar customers, and "small impact is possible" depending on ECA proportions on solar versus non-solar customer bills.[18]

Q. How is the Company's proposal discriminatory?

A. The Company is singling out a particular behavior of a small subset of customers for special treatment based upon <u>how</u> they reduce their consumption, independent of <u>how much</u> they reduce their consumption. The Company believes that any customer that installs <u>any</u> amount of DSG is receiving a "net metering incentive." The implications

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[15] Response to VSI4-22.
[16] Response to WRA2-15.
[17] Response to VSI4-11.
[18] Response to VSI7-3.

of this view are far reaching. For example, if a customer reduces its consumption through on-site solar energy supplements with a single solar panel that generates on average 30 kWh per month, the Company would treat it as part of the "net metering incentive" calculation. The new reduced load however is likely to fall well within the range of consumption levels of non-net metered customers, yet the former would be subject to discriminatory treatment by the utility.

Are sales reductions resulting from a shrinking household, replacing an appliance with a more efficient one, changing out light bulbs, or making sure your kids turn off their X-Box at night, receiving a "net metering incentive?" Clearly not. What about the very significant sales changes due to weather and economic conditions? The Company is discriminating against one very narrow set of customers that are similarly situated with others.

Conversely, to the extent a group of customers <u>increase</u> load through use of new appliances or charging electric vehicles, should they receive payments from other customers because of the increased fixed costs they are now paying to PSCo? Will the Company propose an "EV incentive?"

The Company does not have the right to tell its customers how much electricity to consume.

Q. Are you opposed to examining the costs and benefits of various utility programs, or sales changes in general?

A. No. I do not have a problem with performing a legitimate comparison of the costs and benefits of deploying customer-installed solar generation systems to the utility, its customers, and society in general. However, there is a need for a robust discussion on the methodologies to be used to assess such costs and benefits, and a discussion on how the resulting analysis may be used in a non-discriminatory fashion. This discussion has not occurred, and in my view cannot occur comprehensively in a litigated proceeding.

Q. How is the Company's so-called "net metering incentive" determined?

A. As Mr. Brockett explains in his testimony, he calculates the proposed "net metering incentive" by subtracting the Company's determination of avoided costs associated with DSG from the calculated revenue loss by customer class to calculate a year-by-year differential expressed on a $/kWh of solar generation basis. These factors were multiplied by the projected solar generation to produce the Company's estimate of net cost/benefit by year.

5. The Company's Revenue Loss Estimates

Q. Do you have any concerns with the determination of revenue loss by customer class, i.e. the "cost" side of the equation?

A. Yes. The Company incorporates numerous approximations, assumptions, and inconsistencies in the data and analyses that are fatal to the Company's proposal. Add to that the analytical shortcomings of the DSG Study[19] and it is clear that the proposal falls short of any evidentiary standard for implementation of such a unique concept. For example, the Company does not have consumption or load data for the actual customers that have installed DSG, nor does it have the corresponding DSG

[19] These are more thoroughly critiqued in Answer Testimony provided by Tom Beach on behalf of TASC.

system size data. Instead, it uses a single average customer consumption and load profile for each of the very diverse classes in which DSG customers reside. As a result, it doesn't know if and when any customers export energy. The load profiles for the SG and PG DSG customers are not only assumed to be average, but are also based on a different period than those used to design rates in the last rate proceeding, potentially compounding the errors. The Company seems to believe that the information it used are "close enough."[20]

Q. How were the effects of DSG by customer class determined?

A. PSCo witness Brockett used the same actual solar profiles found in Exhibit KLS-1 that were the basis for the Effective Load Carrying Capability Study (ELCC). These systems are identified in Tables 9 and 10 in Exhibit KLS-1, for 2009 and 2010, respectively. The DSG systems that were aggregated for the solar generation profile Mr. Brockett used were ostensibly the 14 systems identified for 2010 in Table 10. As it turned out (in response to discovery) the source files actually contained solar generation data only for 7 systems in 2010.[21] Aggregated solar data, whether based on 7 systems or 14 or 15 systems, is improper for determining the effects on individual customer bills.

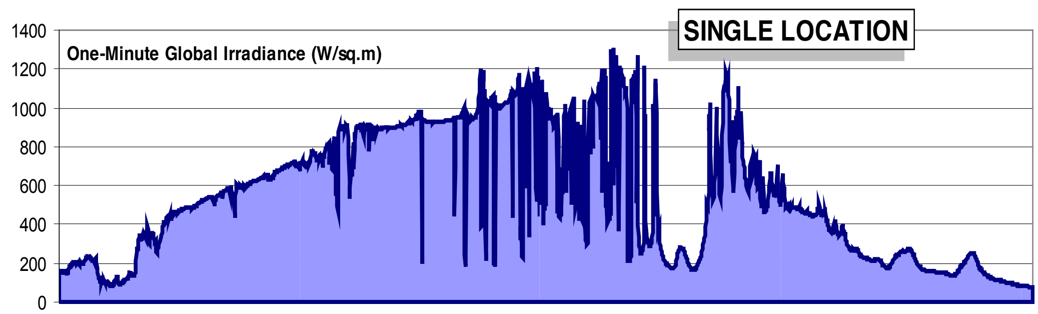
Q. Please describe the concerns you have with using the data set just described for calculating the revenue loss.

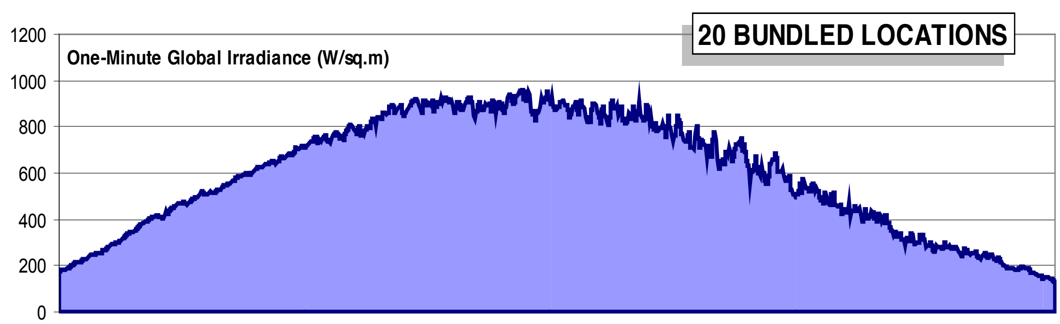
A. It is well know that aggregation of geographically diverse solar generation tends to "fill in the gaps" of individual solar generation profiles that may occur due to cloud

[20] See response to VSI4-42.
[21] See Confidential Attachment VSI4-43.A1.

events, for example, resulting in a much smoother and more predictable solar generation profile. The same is true for customer loads as can be seen in Figure 16 of Exhibit KLS-1. Individual customer loads are volatile whereas the aggregated load is quite smooth. An example solar geographic diversity was provided in a report from the Solar Electric Power Association (SEPA) in May 2008 entitled *Photovoltaic Capacity Valuation Methods*. The following comparison shows plainly the effect described.

CHART 5: SINGLE SYSTEM VS. AGGREGATED SYSTEMS



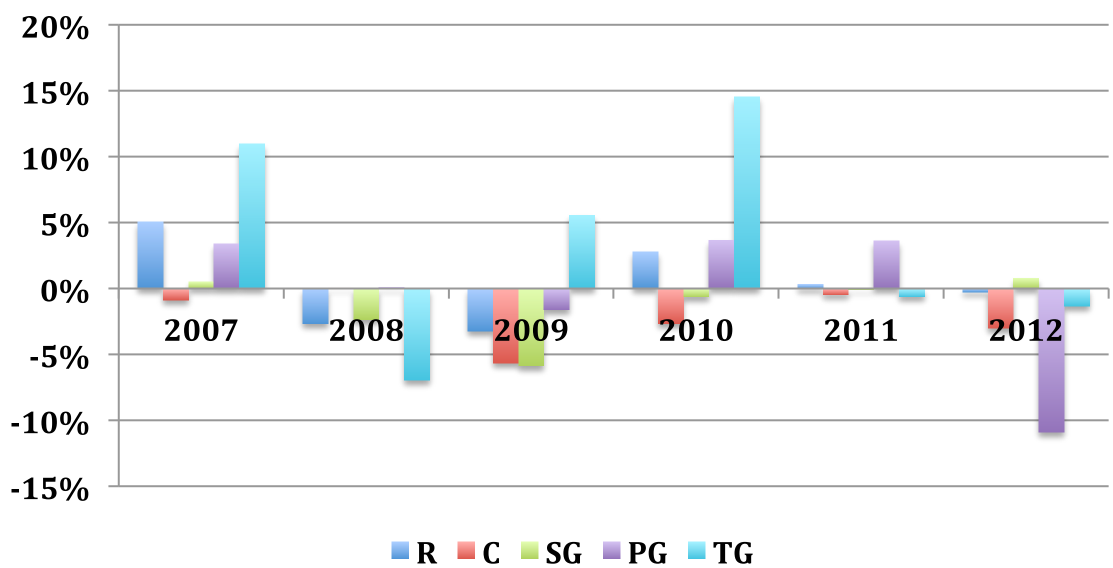


The point is that the output of a single solar generation system can be quite “noisy” while an aggregated group of systems can reduce the noise and smooth out the curve. The implication for utility revenue loss of individual customers resulting from DSG is most notable on the demand charges for customers on the SG or PG rate. Demand charges are based on the maximum 15 minute integrated kW demand during the billing month, thus a single 15’ cloud event in the early afternoon can result in a peak demand by the customer. Thus on an individual customer basis, the impact of solar on demand charges is minimal at best. Use of an aggregated set of solar electric systems, as Mr. Brockett has done in Exhibit SBB-1, results in an overstatement of the demand revenue loss by the Company, and cannot be relied upon as representative of revenue loss.

Q. **Does the year selected for the average consumption in a rate class matter?**

A. Yes. The characteristics of the “average customer” can change significantly from year to year as shown in the following chart:[22]

Chart 6: Annual Average Consumption Variation



Year to year variations can have significant impact on the average consumption used as the basis for the revenue loss calculation. Without any demonstration that data for the retail customers that actually host the DSG systems bears some relationship to the

[22] Derived from data supplied in response to VSI5-17.

average customer class data used by Mr. Brockett in his calculations, and some temporal relationship to single system solar generation data, the Company's revenue loss methodology cannot be the basis for the cost side of the net metering equation.

Q. What is the source of the solar generation information used in the determination of the "net metering incentive?"

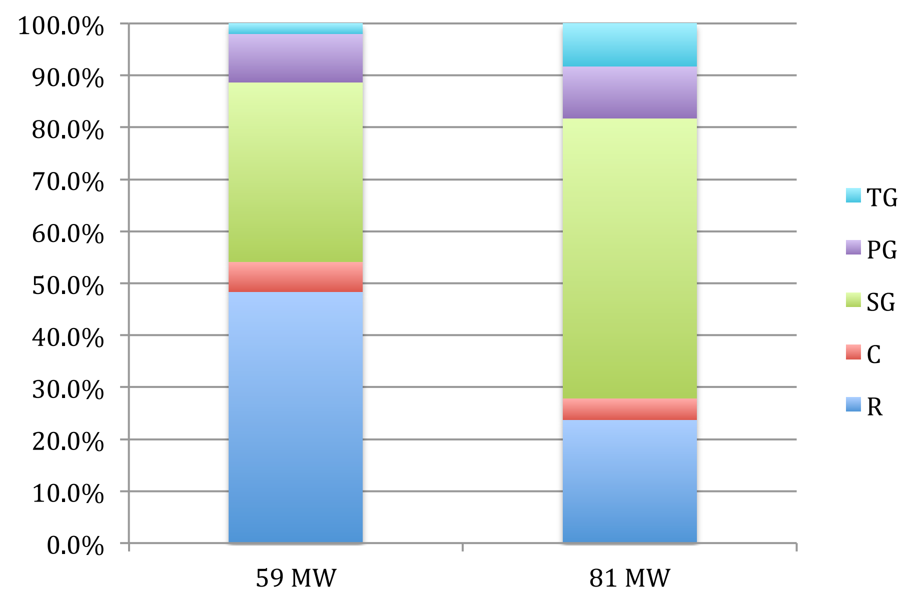
A. The size of the systems assumed for each load class is based upon the average size installed by class prior to September 30, 2010[23] known as the first tranche (59 MW). The second tranche represented an additional 81 MW anticipated to be deployed by the end of 2014.

Q. Are the characteristics of the two tranches of DSG similar?

A. No, the characteristics of these two tranches are quite different. For example, nearly half of the first tranche are residential customers, while in the second tranche only about one-quarter of the customers are residential. Based on Table 4 in the DSG Study, residential systems produce less energy per installed kW than do non-residential systems. Thus, the higher penetration of DSG on non-residential retail customers will of the second tranche will generate greater benefits and produce lower cost, in the form of reduced retail revenue, than the first. Chart 6 graphically depicts the differences.

[23] See response to VSI4-43.

Chart 7: Comparison of Tranches



Q. What is the current actual mix of Solar*Rewards customers on the system?

A. The Company does not know.[24]

Q. Do you have other issues with the determination of the Company's "net metering incentive" proposal?

A. Yes. The Company's proposed NMI is based on a year-by-year comparison of the DSG Study-derived solar values or benefits with the reduction in revenue related to reduction in sales. There is a basic flaw with this approach related to retail rates and ratemaking.

Regardless of the test period used, a rate proceeding establishes rates that are forward looking, based on the principle that the relationships between revenue and costs (as adjusted) will be representative of future conditions post-rate case. In other words,

[24] See responses to VSI1-31, VSI2-23, VSI4-1 and VSI4-45.

rates are designed to recover the costs that will be incurred during the time the rates are in effect. By segregating the values of DSG into year-by-year levels, these benefits are undervalued. DSG is a one-time capital investment that provides benefits over its lifetime, usually at least 20 years. These benefits may not occur in year one or two, but they will occur.

Additionally, rates are designed to recover costs equitably from classes based on the costs they impose, yet the effects of the DSG on the system have yet to be fully incorporated into the determination of rates, including the beneficial effects of DSG on class allocation factors. The allocation bases for major categories of fixed costs are as follows:[25]

- Production – 4CP "Average and Excess Demand "AED
- Transmission – 4CP AED
- Primary Distribution – "Non-Coincident Peak" NCP Max Class Demands
- Secondary Distribution – Blend of NCP Max Class Demands and sum of the individual Max Demands

The effect of DSG on the class allocation factors will be to reduce class cost responsibility in some proportion to the amount of DSG within the class, the capacity value to the class, the individual capacity benefits to the DSG host customers, and so forth. These issues need to be addressed in a rate case before we can say with any degree of confidence that <u>any</u> revenue loss is representative of a cost that will be passed on to other customers.

[25] Response to VSI1-4.

Q. Are you aware of any analogous situations in the existing regulatory paradigm that may be instructive here?

A. Yes. This view of long-term asset deployment is similar to utility investments in lumpy centralized generation. The actual need for additional generation in the year a plant is built is usually far smaller than the size of the plant, but because of economies of scale, larger plants are often built. Retail electric customers then pay higher rates in the near term for capacity not needed – effectively subsidizing future customers. This has become a generally accepted regulatory practice because the present value of future revenue requirements is found to be lower for the resource selected and built than alternatives. Indeed, due to lengthy construction cycles, the costs of the asset during its construction period are sometimes also included in rate base on which the utility is allowed to earn a return.

Similarly, the fair way to take the value of DSG into account is to compare present values of costs and benefits, and not a year-by-year embedded cost comparison.

6. The Company's Avoided Cost Estimates

Q. How are the avoided costs associated with DSG estimated?

A. The Company performed a study entitled "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System" ("DSG Study" or "Study") which serves as the underlying basis for avoided costs in the "net metering incentive." It's important to note that several factors of the DSG Study has been changed or updated since it was provided to TRC members on April 1 and submitted in the M docket including the fuel hedge value, avoided energy costs, avoided capacity costs, solar integration costs, and avoided emission costs.[26]

Q. Please describe the DSG Study.

A. The DSG study was scoped in 2010 and was performed to investigate and document the costs and benefits of distributed solar generation on the Company's electric system at then current penetration levels and at levels anticipated over the relative near-term. The Study was based upon actual Solar*Rewards data from systems deployed through September 2010 totaling 59MW (the first tranche), and an additional 81MW projected to be in place by the end of 2014 (the second tranche).

It should be noted the tasks reflected in the original DSG Study Scope have been rearranged and slightly modified in the PSCo DSG Study Exhibit KLS-1. For ease of cross-reference, the following table summarizes the changes.

Table 4: DSG Study Task Changes

Task	Sept 2010 DSG Study Scope	PSCo DSG Study (KLS-1)
1	Survey and summary of prior DSG studies	Survey, review, and summarize prior DSG studies
2	Characterize Solar Generation and determine correlation to load	Characterize Solar Generation and determine correlation to load
3	Calculate costs and benefits to the distribution system	Calculate costs and benefits to the generation system
4	Calculate costs and benefits to the transmission system	Calculate costs and benefits to the distribution system
5	Calculate costs and benefits to the generation portfolio	Calculate costs and benefits to the transmission system
6	Investigate Winning DSG Business Cases	Document DSG costs

[26] See responses to VSI1-20 and VSI4-7.

In my discussion, I refer to the PSCo *rearranged* task designations as set forth in Exhibit KLS-1 to avoid confusion. TASC presents a witness who addresses the details of individual value elements of the DSG Study.

Q. **Please highlight your primary concerns with the DSG Study.**

A. There are a number of problem areas in the DSG Study that I will address. I have a number of concerns with the approach used by the Company in this section. As a preliminary matter, there is a general lack of consistency among displaced energy costs, avoided generation capacity costs, avoided O&M costs and avoided environmental costs. These three production-related elements should be consistent.

I also question the degree of comparability between the DSG Study ProSym modeling and the updated RES Plan Strategist modeling.

Next, the hedge value ascribed to natural gas prices is undervalued, and falls short of providing an equivalent value to DSG.

Finally, the capacity value resulting from the Company's updated ELCC study lacks sufficient support and is based upon too small a generation data set.

Q. **Why do you take issue with the DSG Study update by Mr. Hancock?**

A. I question the comparability of the update with the original DSG Study. The explanation of the update is described in a single question and answer in the testimony of Mr. Hancock, in which he states at page 20:

> "I supplied to Mr. Brockett two pieces of information i) the avoided costs associated with on-site solar resources, and ii) a projection of the ECA based upon the Strategist calculated fuel costs. The avoided costs were calculated based on the model runs for the RES and No-RES Plans as I have presented in my testimony, and the projection of the ECA is based upon the total fuel costs

calculated in the base RES Plan."

The original Prosym modeling in the DSG Study resulted in "large variations in the annual avoided cost calculations between the two cases" (Exhibit KLS-1, page 20), due primarily to "thermal generation unit start cost variations." The Company found sufficient cause to abandon the two-case comparison approach and instead utilized an hourly weighted marginal energy cost from the base ProSym case. Instead, it utilized the marginal energy costs of the Prosym base case simulation.[27] There was no discussion of the problems experienced with ProSym in the testimony of Mr. Hancock.

Comparing RES and No-RES plans using "Strategist" is considerably different than comparing DSG and No-DSG plans using "ProSym." The two have not been shown to be comparable, nor has the Company demonstrated the update can be relied upon.

Q. What is the problem with the fuel price hedge value utilized by the Company?

A. I do not agree that a fuel hedge value in combination with a long-term price forecast is comparable with the fixed zero-volatility nature of the "fuel costs" of DSG.

The Company has determined a base case avoided energy cost of $52.10/MWh in the DSG Study, and claimed a fuel hedge value of $6.60/MWh..

A recent LBNL study[28] (March, 2013) reported that, based on the February EIA Short Term Energy Outlook, the market believed with 95% confidence that gas prices could potentially rise 1.8 times as much as they could fall by December 2014. With gas price risk so heavily skewed to the upside, now could be an opportune time to hedge

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[27] Exhibit KLS-1, page 21

[28] Bolinger, Mark, LBNL, *Revisiting the Long-term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, March 2013.

natural gas costs. It goes on to say "Bilateral physical supply contracts are available, but only over the short-to-mid-term (10-year contracts are a rarity), and impose significant counterparty default risk due to the perils inherent in fixing the price of a notoriously volatile commodity."

Despite this warning and to its credit, the Company has managed to secure not one, but two 10 year contracts for natural gas. While the terms for the first one are fairly well known, those for the second are secret.[29]

Q. Is the term for acquisition of DSG generated renewable energy credits under the Solar*Rewards program comparable to the natural gas contracts?

A. No. The term for the solar RECs is twenty years. In other words, RECs from DSG are essentially a fixed price for the full 20 years, whereas the length of the gas contracts is 10 years. A longer-term fixed price contract has more value than a shorter term contract.

Q. Does the Company have any insight on the gas price for contracts longer than ten years?

A. No. The Company said it was "aware of" two gas supply transactions with terms longer than ten years, but did not know the actual term of the contracts.

Q. Does the addition of the hedge value to the gas price forecast essentially set a long-term price for natural gas?

A. No, it does not. The Company was very clear in its DSG Study:

> Thus the benefit of such a fuel price hedge is not in guaranteeing lower electricity

[29] See response to VSI2-53.

> prices for the future, but in lessening the likelihood of high future fuel costs.[30] (emphasis in original)

Therefore, the use of a fuel price hedge in conjunction with gas price projections is not comparable to the fuel price stability provided by DSG.

Q. Is there a method to determine a comparably stable long-term gas price?

A. The only truly comparable long term value would be found in a 20 year natural gas contract, whether fixed price or with an escalator.

Q. Does the Company have an estimate for the price of a 20-year natural gas contract?

A. No, it does not.[31]

Q. Is there another way of determining a comparable guaranteed 20-year natural gas price?

A. Given the lack of long term contracts available, another way of identifying similar values is to determine a fixed natural gas price that, if collected from customers for every MCF burned in its facilities, the Company believes would allow it to pay for all future gas costs for the next 20 years. When asked what this amount might be, the Company objected stating such information is not in a form that currently exists or would require a special study.[32]

Q. Has this issue come up elsewhere?

A. Yes. In Minnesota, the Company, Vote Solar and many others have been involved in a workshop process facilitated by the Department of Commerce to develop a Value of

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[30] Exhibit KLS-1, page 6.
[31] See response to VSI3-2.
[32] See response to VSI2-55.

Solar Tariff methodology as a result of legislation passed in the 2013 session. Determining the value of solar for a VOST approach is essentially the same as determining the value of solar for the benefits portion of the cost/benefit analysis for net metering. Thus, the process and the results there can be instructive here.

Common elements of all of these studies are (1) the avoided fuel cost and (2) what to do about the uncertainty of future fuel prices. DSG eliminates uncertainty regarding future fuel prices as it has a fixed zero cost of fuel. The Minnesota Department of Commerce, through its consultant, released its draft methodology on November 19.[33] The section of the report addressing this issue is as follows:

> **Avoided Fuel Cost**
>
> PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.
>
> The methodology provides for three options to accomplish this:
>
> - Futures Market. This option is described in detail below, and is based on the NYMEX NG futures with a 4.75% escalation for years beyond the 12-year trading period.
> - Long Term Price Quotation. This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.
> - Utility-guaranteed Price. This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.
>
> Table 8 presents the calculation of the economic value of avoided fuel costs.
>
> For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX futures, with each monthly price averaged to give a 12-month average in $ per MMBtu. Prices for years beyond this NYMEX limit are calculated by applying the assumed annual

[33] See http://mn.gov/commerce/energy/images/DRAFT-MN-VOS-Methodology-111913.pdf

> NYMEX price escalation. An assumed fuel price overhead amount, escalated by year using the assumed NYMEX price escalation, is added to the fuel price to give the burnertip fuel price.

Note that Minnesota uses 25 years as the term of these agreements based on the assumed life of a PV system.

Q. Do you propose similar treatment here for avoided energy costs?

A. Yes. The Company uses the sum of its gas price projections and fuel hedge value, or about 5.87 cents/kWh, as the value it is avoiding by locking in a fixed 20-year energy cost from its DSG customers. It should at a minimum fully remove the natural gas price volatility risk by locking in the same gas price for the next 20 years for all its retail customers. In other words, natural gas prices should be removed from recovery through the ECA and included as an expense in rates like any other relatively stable production expense. If the Company believes this figure is incorrect, it should come forward with a number it is willing to lock in for 20 years, and use that figure as the energy cost avoided by DSG in its value analysis. Thus both DSG customers and non-DSG customers would be treated consistently.

Q. Do you oppose the use of the Company's updated ELCC Study for the purposes of determining DSG capacity value?

A. Yes. The changes in capacity value from the PSCo 2009 ELCC Study to the one contained in Exhibit KLS-1 (updated in 2012) are large and unexplained. There was a dramatic decrease in capacity value between the two studies in each region that the Company has not been able to explain.[34] Without a detailed explanation of the

[34] See response to VSI2-43 and 44.

changes, the 2012 ELCC study should be rejected and either the 2009 Study substituted or another method that is more transparent.

Q. Do you have any thoughts as to what may have caused the dramatic changes in capacity values from the 2009 study to the 2012 study?

A. Yes. I discussed above the problems with using the solar generation profile from the sample of systems in Table 10 on page 15 of Exhibit KLS-1 for the purpose of determining the impact DSG would have on an individual customer's demand charges. In a nutshell, the problem is that aggregating multiple generator data smooths the profile and results in improper demand offsets for a single customer, overestimating revenue loss. Here, the problem with using the same data is the opposite - a profile purportedly based on 9 or 14 individual systems (Exhibit KLS-1), but in reality 5 or 7, respectively as provided in response to VSI4-43, to represent in excess of 10,000 systems falls short of capturing the fullest extent of the diversity among those systems.

Therefore, the capacity values determined in the Company's updated ELCC study must be rejected, and a substitute used. A fair and comprehensive benefit study should use the 2009 ELCC study.

Q. Please explain your concern regarding the effect of DSG systems in Boulder.

A. The Company spends three paragraphs on pages 25 and 26 of the DSG Study describing, or more accurately - speculating, about the impacts of the mountains on generation capacity credit, especially on systems in Boulder. Despite this discussion, the Company admitted that the described effect "had no impact on the ELCC study."[35] As such, this section is irrelevant and should be stricken from the Study. This mischaracterization does however re-emphasize that there is precious little explanation of the large changes in values from the 2009 study to the 2012 study.

Q. Do you have any concerns with DSG Study Task 1 – the survey and summary of prior DSG studies?

A. Yes. Over 3 years has passed since the Commission's approval of the Study scope. During this time, much has happened in the utility industry and in the distributed solar industry that is relevant to this conversation about the benefits that DSG delivers to the utility system, and thus to all ratepayers.

The value of distributed solar generation facilities is a topic that utilities, Commissions, the solar industry and other stakeholders across the country are assessing. The Rocky Mountain Institute (RMI) Electricity Innovation Lab recently released a "Review of Solar PV Benefit and Cost Studies" in which it examined 15 studies from a variety of sources, including most of those referenced in the Company's DSG Study. Notably, the seven most recent studies in the RMI report were not reviewed by PSCo. Indeed, only one of the nine studies released since the beginning of 2011 was included on the list of studies reviewed by PSCo.

Q. Why should this be a concern?

A. The concern is that methodologies and techniques for identifying and analyzing the costs and benefits have evolved over time, and the more recent studies are more comprehensive in nature. Yet, the Company takes the position that all of the benefits

[35] See responses to VSI2-51 and VSI4-34.

of DSG are captured in their DSG study[36] and that no changes were made as a result of its review.[37] The Company makes the claim that "[e]ach utility among those studied differs with respect to such parameters as: customer load shape, predicted load growth, solar resource, existing generation portfolio, and access to organized electricity markets." Without any supporting evidence or documentation, the Company claims that the differences are so "significant" as to not even be worth studying.[38]

Q. Do you agree?

A. No. My experience in these types of issues suggests that there is not as much difference as the Company suggests on at least some of these factors. For example, most utilities have natural gas generation on the margin through a combination of combined cycle and combustion turbines. In addition, customer class load shapes are surprisingly consistent across the country. Thus, it was improper for the Company to completely ignore the other studies.

Q. Do you have any concerns with the solar characterization in DSG Study Task 2?

A. Yes. The Company used a PV degradation factor of 0.75% per year although it acknowledged that 0.5% is NREL's most recent projected degradation factor. It based its 50% increase in degradation on "factors other than panel degradation [that] are expected to affect the performance of DSG systems over time." According to PSCo, these other factors include "increased panel shading over time, degradation in wiring and inverter performance over time, the removal of complete systems prior to

36 See response to VSI1-50.
37 See response to VSI5-13.
38 See response to VSI4-28.

the end of the 20 year life assumption and the potential long-term impacts of bankruptcies of PV equipment manufacturers and third-party system owners." The Company admitted however that it has not documented any of these other factors and has no support for the use of the higher degradation factor.[39] As such it is purely speculative and should be rejected. A fair and comprehensive benefit study should use the 0.5% degradation factor.

Q. Do you have any concerns with the correlation to load in DSG Study Task 2?

A. Yes. Company repeatedly highlights the lower correlation of the solar generation profile with residential load yet downplays the high correlation with non-residential load. Charts 1 – 3 above clearly show the correlation. This is important because only about one-third of the total MW in the DSG Study are connected with residential load.

Q. Do you have any further comments regarding the DSG Study?

A. Yes. I have several. Exhibit KLS-1 refers to "PV inverter trips" in four places to imply the reliability of DSG on its system is questionable. However, despite these references, the Company has not studied, reviewed, analyzed or reported on actual "PV inverter trips" on the PSCo System.[40] Thus, these references should be ignored completely.

Next, it should be noted that as long as the RESA account is in a deficit position, amounts added to that account such as the "net metering incentive" suggested by the Company will allow it to earn additional amounts. This proposal allows the

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[39] See response to VSI2-30.
[40] See response to VSI2-68.

Company to earn a return on its determination of net lost revenue from a sales reduction. This concept is a significant and important policy change and should not be approved lightly.

I also have a practical concern. Each time there is a change to electric base rates or to one of the automatic cost adjustment clauses, there will be a change in the "net metering incentive" necessitating a recalculation. In the words of the Company:

> The class-specific estimates will change each time the level of any base rate or rider changes. Base rates will generally change as a result of a Commission Order in a general rate proceeding, while riders will usually be updated through other filings submitted on a quarterly, biannual or annual basis. In addition, the class-specific estimates will change each time the avoided costs are updated.[41]

The Company listed its riders in response to VSI4-61 as follows:

<u>Electric Rate Adjustments</u>
Occupation Tax Surcharge
Base Rate Adjustments
- Earnings Sharing Adjustment (ESA)
- Significant Revenue Reduction Adjustment (SRRA)
- Quality of Service Plan (QSP)
- General Rate Schedule Adjustment (GRSA)

Non-Base Rate Adjustments
- Demand Side Management Cost Adjustment (DSMCA)
- Purchase Capacity Cost Adjustment (PCCA)
- Transmission Cost Adjustment (TCA)
- Electric Commodity Adjustment (ECA)

Total Rate Adjustments
- Renewable Energy Standard Adjustment (RESA)

[41] See response to VSI1-18(b).

Correspondingly, the solar characterization and each of the benefits underlying future determinations of the "net metering incentive" will change over time from those used in the 2014 RES Plan, yet the Company has no plans to update the DSG study in the future.[42]

Q. Please summarize your testimony regarding the concerns with the proposed "net metering incentive."

A. The Company has not provided sufficient and reliable supporting evidence on which to base it proposed "net metering incentive."

- Permissibility: The Commission Rules, notably Rule 3661(c), do not provide for the types of costs that the Company now seeks to recover through its RESA mechanism.
- Discriminatory treatment: Sales reductions resulting from DSG are too small to matter, and are well within the bounds of other sales changes that occur for other reasons. Singling out a subset of customers reducing energy purchases from PSCo without considering other customers similarly reducing or increasing purchases is discriminatory and akin to single issue ratemaking.
- Overstated revenue loss: The information PSCo used for the cost (revenue loss) side of the equation is based on broad averages that have not been shown to be representative of the customers actually installing DG. The Company's use of improper aggregated solar generation data overestimates revenue loss.

[42] See response to VSI1-18(c).

- Unaccounted ratemaking effects: The effects of DSG on class allocation factors in a rate case will change cost causation and rate relationships, and without a rate case review will result in biases in the cost/benefit relationship, and thus the "net metering incentive."
- No practical effect of proposal: The Company admits that its proposal does not change its revenue or earnings, and impacts on the revenue collected from individual customers are not material, at least on non-DSG customers. The only practical effect of he proposal is to allow it to earn a return on new amounts added to the RESA. The Company should not be using the formal PUC process and its customers as a laboratory.
- DSG Study flawed: The information used for the benefits (avoided cost) side of the equation contains both methodological and data related flaws that render it useless for its intended purpose including the following:
  - The use of a year by year comparison of costs and benefits rather than the more widely accepted levelized costs and benefits,
  - The lack of consistency between avoided fuel and avoided capacity costs,
  - The non-comparability of a hedged natural gas price with a 20 year fixed price solar contract,
  - The use of improper data in the ELCC, and
  - The unsupported 50% inflation of the PV degradation rate.
- As a practical matter, the Company's proposed "net metering incentive" will require a great deal of tedious updating of a proper cost and benefit study each

time rates or adjustment clauses are changed. It is Vote Solar's view that the administrative cost of such maintenance to all parties, including the Commission, needs to be taken into account as a potential avoided cost if net metering is left as currently structured.

Q. Does Vote Solar have any other concerns?

A. Yes. Vote Solar worries that PSCo's "net metering incentive" proposal may be the first step in a series of proposed changes to distributed solar generation policy that will harm the economics of one of the very few clean and local electricity alternatives available to retail electricity customers. Thus we urge the Commission to give especially deep consideration of the ramifications of its decision in this proceeding.

7. The Requirement to Pay for Production Meters

Q. What is the Company proposing with respect to production meters?

A. The Company is proposing to deploy production meters on all DSG systems.

Q. Do you oppose the Company's proposal?

A. Yes, for systems under 10 kW that are owned by the host consumer. Commission Rule 4 CCR 723-3664(f)(2) states as follows:

> For systems ten kW and smaller, an additional meter may be installed under either of the following circumstances:
>
> (A) The QRU may install an additional production meter on the solar renewable energy system output at <u>its own expense</u> if the customer consents
>
> (B) The customer may request that the QRU install a production meter on the solar renewable energy system output in addition to the revenue meter at the customer's expense.

I take no position regarding the Company's proposal to charge customers for production metering for systems above 10 kW.

8. Utility Operations, Economics and Risk

Q. Have the Company's operations changed as a result of the current or projected levels of DSG?

A. No. In response to discovery, the Company indicated it is "pursuing a better understanding of the issues that will be coming with higher small PV penetrations" but that it is "presently using our normal response practices for the few areas that we have with elevated small PV concentrations."[43] When asked to identify actions the Company is taking to accommodate expansion of customer-sited generation, it replied:[44]

> "Concerning Electric Distribution Operations for small distributed generation facilities, we have not taken any specific actions to accommodate expansion but are considering protocols for use in areas where higher concentrations of small PV pose system issues. Electric Distribution Operations works with and develops custom solutions to accommodate large DG.
>
> Concerning Commercial Operations' electric system operations, no additional electric system operation protocols are required to accommodate expansion of customer-sited solar. As part of its forecasting endeavors with the National Center for Atmospheric Research, Public Service is investigating methods for improving solar generation forecasting to improve economic electric system operation."

The implication of these responses is to convey a lack of any sense of urgency related to expanded DSG on its system.

Q. Do you have comments you would like to make with respect to the future relationship between the Company and DSG?

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[43] Response to VSI4-25.
[44] Response to VSI1-57.

A. Yes. In its submittal, the Company takes a very traditional look at the effect of DSG on its system, attempting to fit this new round peg into its square hole of utility operations, cost recovery, and risk. However, PSCo does seem to anticipate higher levels of DSG. Indeed, it has been involved in a number of analyses related to increasing the ability of the Company to integrate larger amounts of DSG onto its grid.[45]

At the same time, the Company view Colorado DSG as attempting to break out of its (PSCo-described) "niche market" status, as witness Hyde urges the Company and the Commission to "ultimately consider the true economics of roof top solar and whether it is the most cost-effective way to acquire renewable energy and achieve environmental improvement."[46]

We agree. For the Company, we know of no other generating resource from which the utility receives the benefits of the generation without paying for the resource. Moreover, the "true economics" can only be discovered through a transparent cost and benefit analysis performed in a thoughtful and unbiased manner, not an incomplete proposal the Company is trying to rush through this litigated proceeding. Finally, it is critical to remember that renewable energy is being acquired for reasons beyond the environmental benefits. Indeed, it is being acquired for the following reasons:

1. *To save consumers and businesses money,*

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[45] For example, in response to VSI5-9, the company describes a project to implement an advanced distribution management system. The scope of the project is not yet complete; however, one of the goals of this project will be to support the safe and reliable integration of distribution energy resources (DER) which include customer sited solar installations.

[46] Direct testimony of Karen Hyde, page 23.

2. *Attract new businesses and jobs,*
3. *Promote development of rural economies,*
4. *Minimize water use for electricity generation,*
5. *Diversify Colorado's energy resources,*
6. *Reduce the impact of volatile fuel prices, and*
7. *Improve the natural environment of the state*

In my view, the Company is taking a significant risk by its actions. Rather than embracing persistent change and working to encourage innovative technologies that can add value to the grid, it is working to slow the spread of DSG in its territory. For example, it has a 1.8% penetration[47] of smart meters on its system, far below many other Western States. It recovers many costs through adjustment clauses that put the risk of mistakes and fluctuations largely on customers, including the largest single expense it occurs annually - fuel. It seeks future test years and recovery of a return on construction work in progress. It promotes demand ratchets that effectively require minimum bills and reduce the benefits of a customer-driven reduction in load. It has not looked at simple changes that could increase the value and opportunity for increased DSG deployment like load shifting programs that could move flexible load to the middle of the day when solar generation is at its maximum.

PSCo's national trade organization, the Edison Electric Institute (EEI) released a report in January 2013 that describes DSG as a disruptive challenge. The Company can rise to that challenge, or it can continue business as usual. If it chooses the latter

[47] See response to VSI1-42.

path, it must recognize that investments in future conventional central station generation and transmission lines could be at risk of becoming stranded or severely under-utilized assets in their lifetimes. Others have similarly downplayed the role of innovative technologies to their companies' peril:

> "There's no chance that the iPhone is going to get any significant market share."
> Steve Ballmer, CEO, Microsoft (2007)

9. Recomendations

Q. What are your recommendations to the Commission?

A. I recommend first that the Commission reject the Company's "net metering incentive" proposal based on the rationale described above. Second, I recommend that the requirement for customers to pay for a production meter be rejected for those customers with DSG systems below 10 kW. Finally, I recommend the Commission convene a series of public workshops to establish a standardized methodology for assessing the benefits and costs of DSG, including potential changes to the regulatory approach for accommodation of innovative technologies.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT A

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Professional Employment

January 2012 to Present: Director of Research and Analysis, The Vote Solar Initiative. Managing the technical and policy research for Vote Solar, and engaging in state, regional, and national campaigns.

March-April 2012: Solar Energy Industries Association - Under a short term and part time contract with SEIA to participate in an Xcel Energy distributed solar generation Technical Review Committee and to manage consulting support also under contract to SEIA.

January 2007 to January 2012: SunEdison, LLC - Various solar policy related positions beginning with Director of Interior West Policy to Managing Director of Western Policy (July 2007), to Vice President of North American Government Affairs (July 2009) to Global Policy Advisor (July 2011). In each of these roles, directed and managed policy research, development and implementation for the company for the various geographies identified at the regulatory and legislative levels.

June 2011 to December 2011: Chair of the Solar Alliance Board.

Dec 1994 to Jan 2007: Senior Energy Policy Advisor, Western Resource Advocates (formerly the Land and Water Fund of the Rockies), Boulder, Colorado. Develop innovative clean energy and air quality public policies within the economic and cultural framework unique to this region. Lead environmental advocate in development of Arizona Environmental Portfolio Standard, Nevada Renewable Portfolio Standard implementation rules, Colorado Renewable Energy Standard legislative proposals, and the 2003 Utah Renewable Energy Standard legislative proposal. Principal author of Colorado's Amendment 37 and lead advocate for related PUC rule development.

Jan 1983 to Dec 1994: Director of Revenue Requirements, Public Service Company of Colorado, Denver, Colorado. Primary responsibility for development of formal rate-related filings for this investor-owned utility for electric, gas, and thermal energy service in two states and the FERC. Developed and responded to a variety of proposed mechanisms to encourage the use of energy efficiency technologies, including innovative rate design approaches.

Dec 1976 to Dec 1982: Technical Witness (Engineer), Federal Energy Regulatory Commission, Washington, D.C. Testified as expert witness on behalf of the FERC in wholesale rate filings on technical, accounting, and economic issues related to rate design, pricing, and other issues.

Education

Masters, Environmental Policy and Management, University of Denver, Denver, Colorado

Bachelor of Science, Electrical Engineering, Rensselaer Polytechnic Institute, Troy, New York

Relevant Publications

Gilliam and Baker, "Green Power to the People," *Solar Today*, July/August 2006.

Dalton & Gilliam, "Walking on Sunshine: Energy Independence on the Rez," *Orion Afield*, Summer, 2002.

Gilliam, Rick, "Revisiting the Winning of the West," *Bulletin of Science, Technology & Society*, April 2002.

Blank, Gilliam, and Wellinghoff, "Breaking Up Is Not So Hard To Do: A Disaggregation Proposal," *The Electricity Journal*, May 1996.

Recognition

Recipient of First Annual Larson-Notari Award, Colorado Renewable Energy Society, June 2005.

Named one of Metro Denver's Top Business Newsmakers, September 2005, Denver Business Journal

Recipient of University of Colorado Wirth Chair Community Award, June 2006.

Summary of Formal Testimonies and Rulemaking Participation

<u>Representing the Vote Solar Initiative</u>

- Public Service Company of CO Docket 13AL-0695E: Line Extension Policy
- Idaho Power Company, Case No. IPC-E-12-27, Net Metering Service
- Arizona Public Service, et al., Docket No. E-01345A-10-0394, et al., RES Compliance
- New Mexico PRC Case No. 11-00218-UT: RPS Reasonable Cost Threshold
- Arizona CC Docket No. E-01933A-12-0291: TEP Rate Case – rate design

<u>Representing Sunedison</u>

- Public Service Co of New Mexico Case No. 10-00037-UT 2010 Procurement Plan
- Public Service Company of CO Docket 09A-772E: 2010 Compliance Plan
- Public Service Company of CO Docket 09AL-299E: 2009 Rate Case Phase 2
- Public Service Company of CO Docket 08A-532E: 2009 Compliance Plan
- Colorado PUC Rulemaking Docket 08R-424E: Renewable Energy Standard Rules
- New Mexico PRC Case No. 08-00084-UT: Reasonable Cost Threshold Rulemaking
- Nevada PUC Docket No. 07-10007: Petition for Declaratory Order re 3rd party ownership
- Public Service Company of CO Docket 07A-447E: 2007 Resource Plan
- Public Service Company of CO Docket 07A-462E: 2008 Compliance Plan
- New Mexico PRC Case No. 07-00157-UT: RPS Rulemaking; diversity standard
- Public Service Company of CO Docket 06A-478E: 2007 Compliance Plan
- Public Service Company of CO Docket 06A-534E: Approval of Alamosa Contract

<u>Representing large commercial customers</u>

- Nevada Power Company Docket No. 02-11037: Electric Tariff Rule related to loss factor associated with metering secondary service at primary level
- Nevada Power Company Docket No. 02-5044: Electric Tariff Rule related to metering

Representing Western Resource Advocates (formerly the Land and Water Fund of the Rockies)

- CO: PSCo Docket 06S-234EG: 2006 Rate Proceeding - Windsource issue
- CO: PSCo Docket 05A-112E: Renewable Energy Standard Rulemaking
- CO: PSCo Docket 05A-288E: Electric Quality of Service Monitoring & Reporting Plan: 2007-08
- CO: PSCo Dockets 06S-016E: Renewable Energy Service Adjustment
- CO: PSCo Consolidated Dockets 04A-214E, 215, 216E: Least-cost Resource Plan
- CO: PSCo Docket No. 04S-164E: Windsource Program & Net Metering in Rate Case Phase 2
- CO: PSCo Docket 02S-315EG: 2002 Rate Proceeding - Windsource issue
- NV: Nevada Power Company Docket No. 01-7016: Demand-side Management Programs
- UT: PacifiCorp Rate Case Docket No. 01-035-10: Demand-side Mgt Cost Recovery
- CO: PSCo Docket No. 00A-008E: IRP - DSM & Wind Resources
- UT: PacifiCorp Rate Case Docket No. 99-035-10: System Benefit Charge Proposal
- AZ: Arizona Restructuring Rulemaking Docket No. 99-205: Renewable Portfolio Standard
- CO: PSCo Docket No. 98A-511E: Air Quality Improvement Rider
- AZ: Arizona Restructuring Rulemaking Docket No. 94-165: Stranded Cost Proceeding
- NV: Nevada Power Company Docket No. 94-7001 (Refiled): Integrated Resource Plan
- NM: Southwestern Public Service Case No. 2678: Merger Proceeding
- CO: PSCo Docket No. 95A-531EG: Merger Proceeding

Representing Public Service Company of Colorado

- PSCo Rate Revenue Requirements Proceeding Docket No. 93S-001EG
- PSCo Demand-side Management & Decoupling Proceeding Docket No. 91A-480EG
- PSCo Incentive Regulation Investigation Docket No. 93I-199EG
- PSCo Rate Proceeding Docket No. 91S-091EG
- PSCo Fort St. Vrain Supplemental Settlement Agreement Docket No. 91A-281E
- Various PSCo FERC rate proceedings, and subsidiary rate proceedings

Representing the Staff of the Federal Energy Regulatory Commission

- Connecticut Light & Power Company, Docket ER 82-301
- Kentucky Utilities Company, Docket ER 81-341
- Philadelphia Electric Company, Docket ER 80-557, et al.
- Minnesota Power & Light Company, Docket ER 80-5
- Boston Edison Company, Docket ER 79-216, et al.
- Connecticut Light & Power Company, Docket ER 78-517
- South Carolina Electric & Gas Company, Docket ER 78-283
- Minnesota Power & Light Company, Docket ER 78-245
- New England Power Company, Docket ER 78-78
- New England Power Company, Docket ER 77-97