Before the
Public Service Commission of Utah

In The Matter of the Investigation of the) Costs and Benefits of Pacificorp's Net) Metering Program)	Docket No. 14-035-114

Direct Testimony of
Tim Woolf

On the Topic of
Net Metering Costs and Benefits

On Behalf of
Utah Clean Energy

June 8, 2017

Table of Contents

List of Exhibits

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency (EPA), U.S. Department of Energy (DOE), U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU) from 2007 through 2011. In that capacity, I was responsible for overseeing a substantial expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the

DPU energy efficiency guidelines; the promulgation of net metering regulations; review and approval of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the Commission, including several electric and gas utility rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director at the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume, attached as Exhibit 2, presents additional details of my professional and educational experience.

Q. Please describe your experience as it relates to cost-effectiveness analyses of electric utility resources.

A. Electric utility resource planning and cost-effectiveness have been central to my career. I have analyzed integrated resource planning policies and practices in many states, prepared several national studies on resource cost-effectiveness practices, and conducted several economic analyses of regional electricity resource options. In November 2016, I prepared a study for Consumers Union on how to develop balanced polices for distributed generation, including an in-depth discussion of how to address cost-effectiveness and cost-shifting impacts of distributed generation.[1]

I am the lead author of the National Standard Practice Manual (NSPM), which was recently released in early May 2017 by the National Efficiency Screening Project.[2] This manual builds off and expands upon the widely-used California Standard Practice Manual, and provides regulators, utilities, efficiency planners, and other stakeholders with a comprehensive framework for assessing utility resources. While the NSPM is focused on energy efficiency resources, the central principles and concepts can be applied to all types of distributed energy resources. The NSPM was prepared by six nationally-recognized experts in energy efficiency cost-effectiveness analyses, and was extensively reviewed by over thirty stakeholders representing regulators, utilities, consumer advocates, government agencies, efficiency experts, and more.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Utah Clean Energy.

Q. Have you previously testified before the Utah Public Service Commission?

A. Yes. I provided direct, rebuttal, and sur-rebuttal testimony in Docket No. 14-035-114, in the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, on behalf of Utah Clean Energy, Sierra Club, and the Alliance for Solar Choice.

---

1 Synapse Energy Economics, *Show Me the Numbers*, prepared for Consumers Union, November 10, 2016.
2 National Efficiency Screening Project, *the National Standard Practice Manual for Assessing the Cost-Effectiveness of Energy Efficiency Resources*, Spring 2017.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and critique the Company's analysis of the benefits and costs associated with distributed generation resources.

Q. Have you coordinated your testimony with any other witness in this docket?

A. Yes. My colleague Melissa Whited is also presenting testimony in this docket on behalf of Utah Clean Energy. Ms. Whited and I worked together to prepare both testimonies, and our testimonies are designed to complement each other. The purpose of her testimony is to review and critique the Company's proposed compensation mechanism for distributed generation.

2. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your primary findings.

A. I make the following findings:

- The Company's proposed net metering compensation mechanism reduces the economics of distributed solar so dramatically that few residential customers will install distributed solar facilities in the future.
- The Company conflates the cost-benefit analysis of net metering with cost-shifting from net metering, resulting in an analysis that does not provide useful information on either effect.
- Contrary to the Company's assertions, its own cost-of-service analyses demonstrate that the benefits of net metering *exceed* the costs.

- This finding is consistent with the Company's 2017 IRP, which finds that increased penetrations of solar distributed generation can reduce the cumulative net present value of revenue requirements by more than $440 million.

- The Company's analysis understates the benefits of net metering by only including one year in its analysis.

- The Company's analysis overstates the cost-shifting of net metering. Therefore, the Company's analysis cannot be used by the Commission to make any findings regarding the extent of cost-shifting from net metering.

Q. Please summarize your recommendations regarding the cost-effectiveness of distributed generation.

A. I recommend that the Commission:

- Find that the benefits of the current net metering program exceed the costs.

- Find that the Company's analysis does not demonstrate that the current net metering program results in cost shifting from net metering to non-net metering customers, due to the limitations of the analysis detailed below.

- Find that future distributed generation compensation mechanism should allow customers to continue to install distributed generation at a reasonable, sustainable growth rate.

- Require that future distributed generation analyses should include separate cost-benefit and cost-shifting analyses To help inform modifications to distributed generation compensation over time. The cost-benefit analysis should be based on revenue requirements and should not include bill credits from distributed generation. The separate cost-shifting analysis should account for the impacts of bill credits.

- Require that future distributed generation cost-benefit analyses should include a study period of 20 years, to account for distributed generation costs and benefits that extend beyond those that occur in a single year.

3. RMP'S PROPOSAL FOR DISTRIBUTED GENERATION COMPENSATION

Q. Please describe the Legislature's requirements set forth in Utah Code Ann. § 54-15-105.1.

A. The statute requires the Commission to

(1) determine, after appropriate notice and opportunity for public comment, whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and

(2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits.

Q. What framework has the Commission established to conduct the analysis under subsection one?

A. In its November 10, 2015 order, the Commission established a framework for assessing the costs and benefits associated with net metering "that affect PacifiCorp's cost of service."[3] The framework is based on the following types of analyses:

1) A comparison between two separate cost of service studies to determine the costs and benefits of the net metering program:
    a. An actual cost of service study ("ACOS") that assumes the distributed generation that occurred in 2015, and
    b. A counterfactual cost of service study ("CFCOS") that assumes no distributed generation occurred in the same time period.
2) An ACOS that segregates distributed generation customers into their own class to determine the impact on other customers.

Q. Please describe the Company's Compliance Filing.

A. On November 9, 2016, Rocky Mountain Power (RMP) submitted its compliance filing in response to the Commission's November 10, 2015 order. In its filing, the Company claims that the analysis demonstrates that the net metering program costs exceed the benefits, rendering the current rate structure unjust and unreasonable because costs are shifted. Because of this, the Company requests that:

1. The Commission approve RMP's proposed three-part tariff for customers with distributed generation,

[3] Utah Public Service Commission, *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-035-114, Order, November 10, 2015, p. 2.

2. The Commission approve new application fees for net metering customers, and

3. Net metering customers be segregated into a distinct rate class.

Q. What tariff is the Company proposing for residential customers with distributed generation?

A. The Company is proposing that residential customers with distributed generation take service on Schedule 5, which is a tariff that consists of a higher customer charge, a demand charge, and a reduced energy (or volumetric) charge as compared to the standard residential tariff. Under the Company's proposed Schedule 5, new distributed generation customers would face an increase in the fixed charge of 150%; a demand charge based on maximum hourly usage; and an energy rate less than half the current rate.

4. RMP'S PROPOSAL WOULD HAVE A CHILLING EFFECT ON THE RESIDENTIAL SOLAR INDUSTRY

Q. How would the Company's proposed Schedule 5 affect the economics of distributed generation in Utah?

A. Because net metering compensation is based on the energy rate, most net metering customers would experience much lower bill savings relative to the current residential tariff. My colleague Melissa Whited calculates the impact that the Company's proposal will have on residential customers who install distributed solar generation. She finds that customers in her sample with monthly consumption of less than 1,200 kWh would, on average, experience reduced bill ranging from $250 to $400 annually. To put this in context, a $300 reduction in annual bill savings translates to a bill impact of more than

$6,000 over 20 years, per customer. A $6,000 reduction in savings would substantially lengthen the payback period for solar customers.

For example, typical residential customers with the same load profile used by Ms. Steward would see their payback period increase from approximately 13 years under current rates to 30 years under the Company's proposed rates.[4] Under such adverse economics, few customers would be willing to install distributed solar in Utah, which would have a chilling effect on the residential solar industry in the state.

5. RMP'S COST-BENEFIT ANALYSIS

Q. Please describe the Company's analysis of the costs and benefits associated with net metering.

A. To estimate the costs and benefits associated with net metering, the Company conducted two cost of service studies:

- An actual cost of service study for calendar year 2015 that includes net metering customers, and
- A counterfactual cost of service study that includes all the same inputs and assumptions, except that it does not include any generation from net metering customers over the same time period.

[4] These estimates are presented in the direct testimony of my colleague Melissa Whited. Her analysis is based on the following assumptions. The load profile and solar generation profile are from those used in Workpaper JRS-7. Load profile results in consumption of 996 kWh. Solar generation was scaled to a 5.68 kW system size, based on the average size of 2012-2015 residential installations from Attach EFCA 1.24, resulting in an average of 660 kWh/month. Assumes $2.93/watt purchase and installation cost (based on NREL's U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016), $1,600 Utah state tax incentive, and 30% federal tax incentive. This analysis does not include financing costs.

Each cost of service study calculates the electricity sales and costs (in terms of revenue requirements) for each customer class and for each type of cost (production, transmission, distribution, meter, etc.). As stated by the Commission, "Comparing the cost of service for the existing classes under the ACOS and CFCOS will show both the total and average cost impact on the existing classes, and this information will be valuable in assessing a just and reasonable rate structure."[5]

Each cost of service study was performed using actual data for the 2015 calendar year. Consequently, this methodology includes only net metering costs and benefits for a single year. Additional impacts from distributed generation for the remainder of the facilities' operating lives are not accounted for.

Q. Please summarize the Company's findings from its cost-benefit analysis.

A. The Company claims that its analysis shows that the current net metering program increases costs to customers in Utah by $2.0 million. The Company also claims that residential net metering customers are responsible for the majority of the increased costs, by creating increased costs of $1.7 million.[6]

Q. How does the Company arrive at this result?

A. Mr. Meredith compares the CFCOS and the ACOS to estimate the benefits and costs of distributed generation. The benefits include lower net power costs, lower class allocations, and lower line losses. The costs include increased metering costs, increased

5 November 10 Order, p. 10
6 Direct Testimony of Robert M. Meredith, p. 6 and Table 1.

engineering and administration costs, and increased customer service and billing costs. Then the Company also adds in bill credits to distributed generation customers as a cost.[7]

Q. Please explain what "bill credits" are in this context.

A. Bill credits represent the amount of revenues that are not collected from distributed generation customers as a result of their generation. The Company describes them as the "revenue difference between actual billed revenue and full revenue requirements," and estimates them by "multiplying the changes in energy by the corresponding energy charges."[8]

Q. Do you agree with the way that the Company has characterized the results of its COS analyses?

A. No. The Company's presentation of the results include costs that are not present in the cost of service studies, and are therefore inconsistent with the Commission's November 2015 order. In that order, the Commission notes that "the Statute requires us to analyze those costs and benefits arising out of the net metering program that affect PacifiCorp's *cost of service*" (emphasis added).[9] Further, the Commission states that "The categories of costs in both studies should generally be consistent with those PacifiCorp employs in preparing cost of service studies for ratemaking purposes."[10]

---

[7] Direct Testimony of Robert M. Merideth, Exhibit RMM_1.
[8] Direct Testimony of Robert M. Merideth, pp. 14-15.
[9] Utah Public Service Commission, *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-035-114, Order, November 10, 2015, p. 2.
[10] Utah Public Service Commission, *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-035-114, Order, November 10, 2015, p. 13.

Q. What costs does the Company include that are not present in the cost of service study?

A. Instead of presenting a comparison of the CFCOS and the ACOS, the Company also adds bill credits to the "costs." Bill credits do not affect the Company's cost of service (i.e., its revenue requirements), as they are not a cost of serving customers. Bill credits represent the "lost revenues" from distributed generation, which are not a cost of serving customers and do not affect RMP's revenue requirements. Thus, according to the framework set forth by the Commission that requires costs and benefits to be consistent with those employed in cost of service studies, bill credits should not be included in the Company's analysis.

Q. Does this mean that bill credits are not relevant?

A. No. Bill credits are relevant to estimating and understanding the extent to which distributed generation might result in cost-shifting from net metering customers to non-net metering customers. However, a cost of service analysis should never include bill credits, since they do not affect the Company's revenue requirements or the cost to serve various types of customers. Bill credits should be considered separately from revenue requirements, as described below.

Q. Please describe what the Company has done in its presentation of the results.

A. In adding bill credits as a "cost," the Company conflates cost-benefit analysis results with cost-shifting analysis, which confuses the issue and does not provide useful information regarding either net benefits or cost-shifting. I discuss the importance of conducting both a cost-benefit analysis *and* a cost-shifting analysis in the following section.

Q. How does the Company's method of including bill credits affect the results of its COS analysis?

A. The bill credits have a dramatic impact on the overall results of the COS analysis. Table 1 presents a summary of the results of RMP's analysis for residential customers, with and without the bill credits considered as a cost.[11] (The rows that are affected by the bill credits are highlighted.) The Company claims that distributed generation results in *increased* costs of $1.659 million, whereas the costs to serve customers are actually *reduced* by $1.328 million.

Table 1. Residential COS Results: Impacts of Bill Credits

	Without Bill Credits	With Bill Credits
Costs ($000):		
Increased metering costs	$112	$112
Increased engineering/administration	$369	$369
Increased customer service/billing cost	$72	$72
Bill credits	$0	$2,987
Total Costs	$553	$3,540
Benefits ($000):		
Lower net power costs	($675)	($675)
Lower class allocation	($1,137)	($1,137)
Lower line losses	($69)	($69)
Total Benefits	($1,881)	($1,881)
Net Cost (Benefit) ($000):	**($1,328)**	**$1,659**

11 All of the information presented in Table 1 is taken from Direct testimony of Robert M. Meredith, Exhibit__(RMM-1), page 3 of 3.

Q. What do the results in Table 1 indicate about the importance of separating the cost-benefit analysis from the cost-shifting analysis?

A. The column in Table 1 labeled "Without Bill Credits" represents the benefit-cost analysis, in that it includes only impacts on the Company's costs to serve customers. The Column labeled "With Bill Credits" presents the combined effect of both a benefit-cost analysis and a cost-shifting analysis.

A comparison of the results in these two columns indicates the importance of separating the cost-benefit analysis results from the cost-shifting results. When the cost-benefit analysis results are presented separately, it is clear that net metering will reduce the costs to serve all residential customers. When the cost-benefit and cost-shifting results are combined, as the Company has done, the analysis becomes muddied, and does not provide any useful information on either net benefits or cost-shifting. Understanding this distinction is critical to developing sound policies to increase net benefits and mitigate against unreasonable cost-shifting.

6. UTILITY COST-BENEFIT ANALYSES

<u>Cost-Benefit Analyses</u>

Q. Please summarize the basic elements of utility cost-benefit analyses.

A. There are a variety of ways that utilities conduct cost-benefit analyses, but at a fundamental level the analysis consists of comparing the utility's revenue requirements under a scenario without the program or resource to a scenario that includes the program or resource. This is akin to the Commission's requirement that the utility compare the results of the CFCOS to the ACOS; the only difference is that the Commission restricted the analysis timeframe to a one-year period, rather than the longer time periods that are more frequently used in utility cost-benefit analyses.

Q. What time period is typically used for utility cost-benefit analyses?

A. Utility cost-benefit analyses generally use forecasts of the costs and benefits over a study period that is long enough to capture at least the operating life of the resource. One or more future scenarios including the resource is compared with one or more future scenarios excluding the resource, and the difference between the scenarios with and without the resource indicates the net costs or net benefits of the resource in question.

Q. How are the results of such analyses typically presented?

A. The net benefit of each scenario is typically presented in terms of revenue requirements, which represents the costs incurred by the utility to serve customers. The cumulative present value of revenue requirements (PVRR) is calculated for each scenario, and the net present value of revenue requirements indicates whether the resource in question will result in net costs or net benefits for utility customers.

The integrated resource planning (IRP) process is an example of such an analysis, where electricity resource portfolios are compared with alternative portfolios. The primary criterion for identifying the preferred resource plan is PVRR, where the portfolio with the lowest cumulative PVRR is determined to be the preferred portfolio. Other criteria are also applied in selecting the preferred plan, but PVRR is typically the primary criterion.

Q. Is this consistent with RMP's IRP practice?

A. Yes, RMP uses PVRR as the primary criterion for evaluating electricity resources and alternative portfolio scenarios.[12]

Q. Are there aspects of demand-side resources that require different cost-benefit analysis techniques than those used for supply-side resources?

A. In general, no. The same basic concepts and principles should be used for evaluation of both supply-side and demand-side resources. In fact, this is necessary in order to evaluate both types of resources consistently and comparably.[13]

However, there is one important difference between supply-side and demand-side resources that might need to be addressed when evaluating their impacts on customers. Unlike supply-side resource, demand-side resources can create "lost revenues" because of reduced consumption by electricity customers. These lost revenues might, in some cases, result in cost-shifting from customers who install demand-side resources to those who do not. To the extent that regulators and other stakeholders are concerned about the potential cost-shifting from demand-side resources, it is useful to conduct a separate, additional analysis to assess cost-shifting impacts.

---

[12] See, for example, PacifiCorp 2017 Integrated Resource Plan, Volume I, p. 145.

[13] The Commission has a long-standing policy that "demand-side and supply-side resources must be evaluated on a consistent and comparable basis." Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PACIFICORP, Docket No. 90-2035-01, Report and Order on Standards and Guidelines, June 1992, pp. 12-13; p. 35.

The Difference Between Cost-Benefit Analyses and Cost-Shifting

Q. Please explain the difference between cost-benefit analysis and cost-shifting analysis.

A. Cost-benefit analysis is a conventional technique used to identify the costs and benefits of a particular investment, project, or program. It indicates the costs or benefits to all customers as a whole, without distinguishing which customers experience which costs or benefits.

Cost-shifting analysis goes one step further. It indicates the *distributional* impacts of a particular investment, project, or program. It indicates whether some customers' costs might increase, even though other customers' costs might decrease.

Q. Why is it important to distinguish between cost-benefit analysis and distributional (cost-shifting) impacts?

A. A cost-benefit analysis provides different information than a distributional (cost-shifting) analysis.[14] A cost-benefit analysis indicates whether the resource or program has net benefits, and therefore whether it is in the public interest to proceed with the resource or program. A distributional analysis can be used in those instances where regulators wish to know how the resource or program might affect some customers differently than others. The results of both analyses can be used to strike the appropriate balance between promoting cost-effective resources or programs, and mitigating distributional concerns.

[14] This issue is addressed in more detail in a recent Synapse report: *Show Me the Numbers*, prepared for Consumers Union, November 10, 2016, Chapter 5.

Q. Do other utility investments have distributional or cost-shifting impacts?

A. Yes. Many electric utility resource investments can lead to some amount of cost-shifting between customers. Investments in generation, transmission, distribution, and demand-side resources can all have different distributional impacts. It would not be reasonable or in the public interest to limit utility resource investments to those that result in no cost-shifting at all. Such a standard would essentially paralyze a utility from making critical investments necessary to serve all customers as a whole and to reduce costs over the long-term.

This is why it is essential to consider cost-effectiveness separately from distributional impacts. If the two types of impacts are combined into one analysis, then that analysis will mask the separate impacts. Such an analysis will not reveal whether the resource will reduce costs to all customers as a whole, nor will it reveal the magnitude of the distributional effects.

Analyses that do not present the results of the cost-benefit analysis and the distributional impacts separately cannot be used to decide whether to invest in the resource or program, whether the resource or program results in unreasonable distributional impacts, or whether any distributional impacts should be mitigated. In other words, without presenting the distributional impacts separately, it is not possible to determine whether there is a problem, or what might be the right solution if a problem does exist.

Q. Does the Company's presentation of the costs and benefits of the distributed generation compensation mechanism present the net benefits and the distributional impacts separately?

A. No. Mr. Meredith's presentation of the Company's economic analysis combines the cost-effectiveness and distributional impacts, thereby masking both.[15] Table 1 in Section 5 demonstrates how the Company's analysis masks both impacts.

<u>Distributed Generation Facilities as Utility Resources</u>

Q. Your testimony above describes cost-effectiveness practices for electric utility resources in general. Are distributed generation facilities a utility resource?

A. Yes. It is conventional practice in the electric utility industry to consider distributed generation facilities as a resource to the utility system. While distributed generation facilities are typically owned and operated by customers or third-parties, they have generation and capacity impacts on the utility system and they are conventionally considered a utility resource. For many years, they have been referred to as a demand-side resource. In recent years, they have been referred to as a distributed energy resource (DER). Many states around the country are actively considering how best to utilize DERs, including distributed generation, as part of their grid modernization initiatives.

[15] Exhibit RMM_1

Q. Does RMP consider distributed generation as part of its Integrated Resource Plan?

A. Yes. RMP has considered distributed generation in the last three IRPs. In the 2017 IRP the Company finds that solar distributed generation results in net economic benefits to customers, as discussed further in Section 7.

Q. Is the Company able to influence the installation and development of distributed generation facilities, or are these facilities simply a voluntary customer decision outside the control of the Company?

A. RMP can, and will, have a very large influence on the installation and development of distributed generation facilities. The distributed generation compensation established by the Company, and ultimately the Commission, will dramatically affect the economics of distributed solar for customers and therefore will affect the extent to which customers install distributed generation. As described in Section 4 of my testimony, the Company's proposed distributed generation compensation mechanism in this docket would undermine the economics of distributed generation so much that few residential customers would invest in them. Maintaining the current tariff for residential net metering customers would result in significantly more development of distributed generation than the Company's proposal.

As described in the direct testimony of Ms. Whited, distributed generation can be compensated in multiple ways. Modifying the compensation level can be used to achieve a desired level of distributed generation growth in Utah. Compensation rates can be modified over time to account for industry developments and customer response, and to moderate growth if needed. In fact, the distributed generation compensation is the best tool that the Company and the Commission have to strike the appropriate balance between promoting this cost-effective resource and mitigating concerns about distributional effects.

Q. Is it reasonable to expect the Company to forecast the costs and benefits of distributed generation for many years in the future for the purposes of assessing its costs and benefits?

A. Yes. Not only is it reasonable, it is necessary. Electric utilities routinely invest in generation, transmission, distribution, and demand-side resources that last 10, 20, 30 years or more. In many cases, these investments will not provide net benefits to customers for many years into the future. If the long-term costs and benefits of resources are not accounted for when making resource decisions, then the utility will invest in uneconomic resources which will result in higher costs for all customers as a whole. This is a widely-accepted, fundamental premise of electric utility resource planning and regulation.

Q. Is it reasonable to expect the Company to forecast the costs and benefits of distributed generation for many years in the future for the purposes of establishing the distributed generation compensation?

A. Yes. Since the compensation level will clearly affect the amount of distributed generation that is installed by customers, it is necessary to understand the costs and benefits of encouraging greater or lesser amounts of distributed generation (for example, higher and lower levels of distributed generation penetration compared to a base case IRP scenario).

The only way to fully understand the costs and benefits of distributed generation is to account for the long-term impacts of those resources.

Q. Is there a conflict between long-term resource planning and determining compensation levels that affect customers in the short term?

A. No, there is no such conflict. In fact, long-term resource planning should be used to inform rate design and distributed generation compensation mechanisms. The relationship between cost-of-service studies, rate design, and long-term planning is discussed in a recent Synapse study.[16] In sum, long-term resource planning should be used to inform rate design (and distributed generation compensation), by indicating the cost-effectiveness of different resources. Rate designs (and distributed generation compensation) should be developed to send efficient price signals to customers to invest in cost-effective resources. If rate designs (and distributed generation compensation) do not account for the long-term impacts of resource options, then customers will not receive efficient price signals, will not invest in cost-effective resources, and all customers as a whole will incur higher electricity costs.

Q. Has the Commission recognized the importance of the relationship between rate design and long-term planning practices?

A. Yes. The Commission's IRP standards and guidelines require that integrated resource plans include, among other thigs, a "narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in

[16] Synapse Energy Economics, *Show Me the Numbers*, prepared for Consumers Union, November 10, 2016, pages 8-9, Figure 2.

rate design might facilitate integrated resource planning objectives."[17] This requirement indicates the importance of recognizing how rate design can influence long-term planning objectives and outcomes.

7. RMP'S COS ANALYSIS OVERSTATES COST-SHIFTING IMPACTS

Q. How does RMP overstate the cost-shifting impacts of distributed generation?

A. The Company's analysis overstates the cost-shifting impacts of distributed generation in three ways.

1. The analysis undervalues distributed generation benefits, which results in overstating the cost-shifting impacts.
2. The analysis assumes that all lost revenues created by distributed generation will be recovered from customers, when in practice they will not. This also results in overstated cost-shifting impacts.

Each of these points is explained in the following sub-sections.

RMP's COS Analysis Undervalues Distributed Generation Benefits

Q. How does RMP's analysis undervalue distributed generation benefits?

A. The cost-of-service studies used by RMP only cover a small portion of the actual benefits of distributed generation.

[17] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PACIFICORP, Docket No. 90-2035-01, Report and Order on Standards and Guidelines, June 1992, pp. 12-13; p. 35.

Q. Why do the cost of service studies capture only a small portion of the actual benefits of distributed generation?

A. Both the CFCOS and the ACOS are based on a one-year study timeframe. By constraining the study time horizon to only one year (as is done for a typical cost of service study), the analysis fails to account for the ability of distributed generation to avoid or defer long-term system investments. These avoided or deferred costs may be substantial.

Q. The Commission required a one-year timeframe in its November 10, 2015 order. What was the rationale for this decision?

A. The Commission raised concerns that a study period lasting several decades might understate impacts on current RMP customers, stating "Those who are present customers of PacifiCorp may or may not be customers in two decades."[18]

Q. Given the Commission's concerns about a study period lasting several decades, is a one-year study period appropriate?

A. I understand the Commission's concerns about intergenerational equity among ratepayers. However, the a one-year time-frame will only capture a fraction of the costs and benefits of distributed generation, and will fail to capture the longer term benefits associated with avoiding or deferring future utility capital costs.

[18] Nov 10 2015 order at 14.

Q. How does constraining the study period to one year fail to account for the avoidance or deferral of future utility capital costs?

A. Large utility capital investments are typically planned for and initiated several years in advance of a system need. For example, in its IRP, the Company might plan for a new gas power plant to come online in 2022, only to find that, by 2018, load has decreased due to distributed generation and the gas plant can be deferred or avoided entirely. Because a cost of service study only looks at costs that have been incurred in the test year, even a comparison between the CFCOS and the ACOS would not capture the avoided costs associated with distributed generation avoiding or deferring future capital costs.

Q. Is it likely that distributed generation will avoid future utility costs over the long-term?

A. Yes. The Company's most recent IRP estimates the net benefits of different levels of distributed generation on its system. The IRP compares a Low Solar DG case and a High Solar DG case, relative to the Base Case. RMP finds that the Base Case solar DG saves $168 million relative to the Low Solar DG case; and the High Solar DG case saves $440 million relative to the Low Solar DG Case.[19]

[19] PacifiCorp 2017 Integrated Resource Plan, Volume I, pp. 250-251. Costs are presented in terms of cumulative present value dollars over the IRP study period.

Q. What is the consequence of failing to account for distributed generation's avoidance or deferral of large investments when assessing the costs and benefits?

A. If these long-term benefits are not accounted for, then distributed generation will be under-valued. If distributed generation compensation is based on understated distributed generation estimates, then fewer customers will install distributed generation technologies, the potential distributed generation benefits will not be realized, and all customers will pay higher costs for electricity.

<u>RMP's Analysis Overstates the Impacts of Lost Revenues on Customers</u>

Q. The Company's analysis assumes that all lost revenues associated with distributed generation will be recovered in the rates of other customers. Is this assumption correct?

A. No. A portion of lost revenues from distributed generation will be recovered from utility shareholders. Lost revenues from distributed generation are recovered from all customers at the time of a new rate case, when the utility's sales are adjusted to account for the actual sales to customers in the rate case test year. In between rate cases, lost revenues from new distributed generation customers are simply not recovered by the utility. All else being equal, these unrecovered lost revenues will lead to reduced revenues and reduced profits for the utility. At the time of the next rate case, retail sales are adjusted to account for all the distributed generation installed to date, and lost revenues are recovered from customers after that.

Q. Does the Company acknowledge that some of the lost revenues will result in reduced utility revenues and potentially reduced profits?

A. Yes. Mr. Hoogeveen notes that in between rate cases "the Company bears the costs resulting from incremental growth in the number of new net metering customers."[20]

Q. Why is it so important to make this distinction between cost-shifting and reduced utility profits?

A. The difference between cost-shifting and reduced utility profits has significant implications for customers. It also might have important implications for the Commission, and for the regulatory policies that could be used to address these implications. The Commission might place a higher priority on maintaining customer equity than it does on maintaining utility profits.

Q. Under what conditions would the Commission place a higher priority on maintaining customer equity than maintaining utility profits?

A. If a utility has been earning a return on equity that is close to or higher than its allowed return on equity, then there is no reason for the Commission to take actions to maintain or increase utility profits. In this context, the Commission might place a higher priority on protecting customers relative to protecting utility shareholders.

[20] Direct Testimony of Gary Hoogeveen, pp. 4-5.

Q. What does this distinction indicate about the way that the Company has presented the results of its cost-benefit analyses?

A. This distinction has two important implications. First, it indicates that the magnitude of the cost-shifting presented by the Company is overstated. For the distributed generation systems installed in the years between rate cases, the lost revenues will be borne by utility shareholders, not customers, during those years.

Second, the fact that the amount of cost-shifting is overstated by the Company emphasizes the need for presenting the results of the cost-benefit analyses separately from the results of the cost-shifting analyses. Presenting the cost-benefit results separately in terms of only revenue requirements provides a more transparent and meaningful indication of the costs and benefits that will accrue to customers.

8. CONCLUSIONS FROM RMP'S COST-BENEFIT ANALYSIS

Q. Please summarize the key conclusions that can be drawn from RMP's analysis regarding the costs to serve NEM customers.

A. First and foremost, the Company's analysis clearly demonstrates that the current net metering program will reduce revenue requirements for customers. RMP's analysis finds that residential revenue requirements, i.e., the costs to serve residential customers, would be reduced by roughly $1.3 million in the year analyzed. In other words, the Company's analysis demonstrates that current net metering program will provide net benefits to customers. Table 1 presents the Company's results that lead to this conclusion.

Second, the Company's estimates of the overall net benefits of the NEM program are significantly understated as a result of using only a single year of costs and benefits.

Therefore, the actual net benefits from the residential net metering program are likely to be much higher than Company's estimate of $1.3 million per year.

Q. Please summarize the key conclusions that can be drawn from RMP's analysis regarding the cost-shifting (distributional impacts) of the current net metering program.

A. The only conclusion that can be drawn from the Company's analysis regarding cost-shifting is that the estimate of cost-shifting is over-stated. As described in Section 7, the Company has overstated the cost-shifting impacts the current net metering program by (a) overstating the costs; (b) understating the benefits; and (c) assuming that all lost revenues will be recovered from customers when in practice they will not be. The combination of these three effects demonstrates that the cost-shifting effects are clearly too high. As such, the Company's estimates should not be used by the Commission in this docket to make determinations regarding the cost-shifting (distributional) effects of the current or future net metering programs.

Q. Does this conclude your direct testimony?

A. Yes, it does.