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 ELIAH GILFENBAUM

ON BEHALF OF

THE ENERGY FREEDOM COALITION OF AMERICA

JUNE 8, 2017

Q. Please state your name, employer and current position.

A. My name is Eliah Gilfenbaum. I am currently a Manager of Energy Policy at Tesla and SolarCity.

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

A. I am testifying on behalf of the Energy Freedom Coalition of America ("EFCA"). EFCA represents a broad range of businesses that include SolarCity Corporation,[1] Silevo, LLC, Zep Solar, LLC, Go Solar, LLC, 1 Sun Solar Electric, LLC, and Ecological Energy Systems. EFCA member companies manufacture, distribute, develop, and provide rooftop solar PV and other distributed energy equipment, systems, and services to millions of homeowners, businesses, schools, non-profits, and public sector customers in numerous states, including Utah. EFCA participates in utility commission proceedings around the country and advocates on behalf of its members and their customers on net metering and other issues to protect consumer choice and make solar energy available to all Americans.

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

A. No.

Q. Please provide a summary of your educational and professional background.

A. I have over 10 years of experience in the energy industry working on carbon markets, renewable energy procurement, utility resource planning, rate design, and production cost modeling. I spent 4 years at Pacific Gas & Electric (PG&E) as an expert analyst in their resource planning department, where I conducted various types of modeling that was

[1] Tesla, Inc. acquired SolarCity Corporation on November 21, 2016. SolarCity Corporation is now a wholly-owned subsidiary of Tesla, Inc.

incorporated into resource valuation protocols. Examples include Loss of Load Probability (LOLP) studies to assess the Effective Load Carrying Capability (ELCC) and capacity value of renewable resources, and production cost modeling to assess resource integration costs. In that role I also familiarized myself with various approaches to avoided cost modeling for the cost-effectiveness evaluation of demand side resources.

Since joining SolarCity's Policy and Electricity Markets team three years ago, I have participated in various proceedings across the country focused on rate design and assessments of the value of distributed energy resources. My participation in these cases has involved review and analysis of utility marginal cost studies, cost allocation methodologies, rate design models, and value of solar frameworks. I have provided testimony before the Oregon Public Utility Commission on methodologies for assessing the value of distributed solar, and before the Public Utilities Commission of Nevada on methodologies for assessing long-term avoided costs. A full list of my experience is attached in my curriculum vitae as Exhibit EG-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide my critique of Rocky Mountain Power's ("the Company's") evidence of the costs and benefits of the net metering program and to provide my own analysis and adjustments to the cost-of-service ("COS") approach to analyzing the cost and equity impacts of net metering customers. These analyses rebut the Company's rationale for separating NEM customers into a separate rate class.

Q. Please provide a summary of your testimony and recommendations.

A. In Section I, I respond to the Company's COS filings and suggest a modified approach to determining whether customers that meet some of their own electrical requirements with onsite solar generation are adequately contributing to the class COS. Unlike the Company's analysis—and distinct from the Commission's net metering analytical framework—the analysis I perform distinguishes between (1) a customer's solar generation that is consumed behind the meter and (2) the compensation the customer receives for exported electricity in the form of a retail credit. When separating out the issue of compensation for exports, my analysis shows that customers with self-generation contribute the vast majority of the cost of serving them. Based on my analysis, I recommend against creating a separate rate class for customers that engage in net metering, as this has broader policy implications for all customers that might desire to engage in self-supply or otherwise use distributed energy resources to manage their onsite energy consumption.

In Section II, I explain the results of my analysis showing the long-term value of exported energy from NEM facilities. The value of these energy exports, when evaluated over a long-term perspective, is higher than the average retail credit received by NEM customers for those exports.

Before moving to the more detailed analyses in my testimony, however, I provide some context for the magnitude of the "cost shifts" alleged by the Company that underlie the need for this proceeding.

Q. Please describe the "cost shifts" alleged by the Company.

A. According to Ms. Steward's testimony, the cost of net metering for residential customers exceeds the benefits by $1.7 million in 2015 and $6.5 million in 2016, and the Company expects this to increase to $27 million per year by 2020, based on growth projections provided by Navigant Consulting.[2] The magnitude of this alleged cross-subsidy, however, is dwarfed by the cross-subsidization that currently exists by virtue of the Company continuing to collect revenues far in excess of its total cost of service for all classes.

Q. Please explain.

A. Quite simply, the Company is over-earning on its Utah operations, as demonstrated in its recent Results of Operations filings with the Commission[3]. When the Company over-earns, all customers in Utah are cross-subsidizing the Company: paying more for electric service than warranted, when compared with the Company's actual costs of providing electric service. For the twelve months ended December 31, 2016, the Company over-earned by approximately $49.8 million on an unadjusted basis, earning a return on equity (ROE) of 11.37%, whereas the approved ROE is 9.80%. The results are similar with respect to the overall rate of return (ROR): compared with the Company's authorized ROR of 7.56%, the Company actually earned 8.37% on an unadjusted basis, and 7.67% on an adjusted basis. This excess return of 81 basis points (8.37% unadjusted actual return versus 7.56% approved return), when multiplied by an unadjusted rate base of $6.2 billion, represents $49.8 million of earnings over and above the level the Commission has determined reasonable for the Company.

I think it is important to keep these relative figures in mind, as the Commission considers the Company's claims regarding the magnitude of cross-subsidization of NEM customers and the claimed urgency in the need to correct it. The cross-subsidization

[2] Witness Steward's Direct Testimony at p. 2.
[3] https://pscdocs.utah.gov/electric/17docs/1703515/293658RMPUTJAMDec2016ROO4-28-2017.xlsm

currently being borne by all ratepayers in Utah could be cured by the Company simply making a general rate case filing to readjust authorized revenues, which it has opted not to do.

I. Issues Related to the Company's Cost-of-Service Studies

Q. Please describe the cost-of-service (COS) studies the Company included in its "Compliance Filing."

A. The Company performed three COS studies in accordance with the Commission's direction in its Order in Phase I of this proceeding adopting an analytical framework to determine the costs and benefits of the net metering program. The Company performed the following studies using adjusted 2015 test year data (i.e., from the Company's last general rate case): an actual cost of service ("ACOS"), a counterfactual cost of service, ("CFCOS") and a net metering breakout cost of service ("NEM Breakout COS").

Q. Do you agree that the Commission-approved COS analytical framework can provide some information relevant to whether customers with onsite generation are adequately contributing to their cost of service?

A. Yes, the three COS approaches provide some important and relevant information, but this framework does not provide the entire picture about what aspects of the net metering program are driving the Company's results. A more nuanced approach is required to discern whether it is unique characteristics of a subset of customers that is responsible for the cost shifts alleged by the Company in its filing, or whether it is simply a result of an analytical framework that presumes a certain type of crediting mechanism.

Q. What does a COS study reveal as to whether a subset of customers within a customer class is subsidizing or being subsidized by other customers in the class?

A. The COS study framework is limited in that it looks only at the short-term recovery of embedded costs. In a ratemaking context, a COS analysis can help determine the adequacy of revenue recovery from particular classes, and can highlight when inter-class subsidies exist. Such interclass subsidies are an inherent part of ratemaking, and it often falls on the regulator to determine if and when such imbalances are material enough to warrant changes. When the analysis is limited to a single historical test year, however—as it is in the Company's presentation—it is not possible to assess the long-term benefits of a particular resource. While the COS approach has an important role in allocating costs and setting rates, it fails to capture many benefits that occur over time.

Q. Do the Company's COS analyses support the creation of a separate customer rate for NEM customers?

A. No. When analyzed appropriately—by distinguishing between changes in consumption that customers effect on their side of the meter versus energy that they export onto the utility system—the COS analyses fail to demonstrate a principled basis for creating a separate customer class for NEM customers.

Q. Does a customer have to be in the NEM program to receive value for consuming self-generated electricity behind the meter?

A. No. Customers generally have the right to install onsite solar and to utilize that generation output to meet their own electrical needs. From the utility's perspective, a customer that engaged in onsite generation exclusively for self-consumption looks like a reduction in delivered load. The utility does not know how much generation is being produced and consumed behind the customer's meter and is not granting any credit for self-generated electricity. Rather, such customers are responding to price signals to avoid purchases from the utility at the prevailing retail rate for their class. This response is no different from a customer that takes other measures to reduce the delivered load by either engaging in energy conservation measures or installing energy efficient appliances and lighting.

Q. Do you agree that a distinguishing feature of NEM and any other self-generation options available to customers in Utah is that NEM requires the Company to provide a full retail credit to customer-generators for each kWh they export to the grid?

A. Yes. While the billed amount of kWhs for a month is determined over the billing period by netting any exported kWh against the delivered load (kWh), one could view net metering as providing compensation for each exported kWh at the applicable retail rate for that customer's class and schedule. A customer that is not engaged in net metering would have to rely on other policies or technological solutions to receive value for any energy in excess of instantaneous onsite needs.

Q. Does the Commission's analytical framework draw a distinction between generation that is consumed onsite by customer-generators and the value that customers receive for exported energy?

A. No. The Company's COS studies look at customer generation that is consumed behind the meter as lost revenue and count that as a cost of the net metering program. Of course, customers without onsite solar could also engage in other programs, like PURPA, to facilitate self-generation. Lost kWh sales due to behind-the-meter consumption are not unique to net metering. Only the retail credit for energy exports is unique to the NEM program.

Q. How do you propose to isolate the impact of the full retail credit of net metering to determine whether subsidization is occurring?

A. Ultimately, it is possible to derive a long-term value of exported energy, as I have done in Section II, which can be compared to the level of compensation being granted to customer-generators under the current NEM program. The extent of any subsidization—which may flow in either direction (i.e., if customer-generators are creating more value than they are receiving, other non-NEM customers in the class are the beneficiaries)—would be determined by the amount of total customer-generator electricity that is exported to the grid and the relationship between the value of that electricity to the system and the rate that customer-generators receive for that generation (in the aggregate).

Q. Are you suggesting that this approach should be used in lieu of the Commission's Phase I analytical framework for determining the costs and benefits of NEM?

A. No, my testimony on this topic is intended to present supplemental information that provides the Commission additional visibility into how customer-sited generation—as utilized by customer-generators participating in NEM—relates to concerns about cost shifting. As noted above, there are two distinct aspects of net metering: (1) a customer utilizes onsite generation to self-supply and avoid purchases from the utility; and (2) a customer creates excess generation (i.e., not consumed instantaneously) and receives a credit to offset purchases from the grid. The Commission's framework does not distinguish between generation that is consumed behind the meter (which does not rely on the NEM mechanism to provide customers value) and generation that is exported to the grid and accounted for under the NEM mechanism.

Q. Why is it important to make that distinction?

A. This distinction is important for several reasons. First, my understanding is that the framework was developed to address the statutory NEM program, subject to the provisions added by SB 208 requiring the Commission to make a cost-benefit determination on the NEM program. By including all NEM generation in the COS analysis (behind the meter and exports), the Commission is unable to distinguish between the impact of NEM and of any other policy option a customer might take to exercise their right to utilize onsite generation to meet onsite electricity requirements. It is important that the Commission have evidence of this distinction (onsite consumption versus credit for exports) to avoid overly broad policy changes that impact the right to self generate, well beyond the current right to net exported generation against purchases of electricity from the Company.

Second, it is important to understand what net metering customers look like on the basis of delivered load, with the credit for exports excluded from the analysis. The Company is claiming that net metering customers, who offset their purchases through the combination of onsite self-supply and the credit received through the net metering mechanism, are somehow uniquely different than other customers in the residential class. The Company uses a COS basis to justify the need for a separate new rate class for these customers, arguing that they do not recover their full cost to serve (presuming the current NEM framework and a very low value attributable to exported generation).The risk is that any customer engaged in self-generation would be lumped in and implicated in this designation. For that reason, it is important to look at customers with onsite generation on the basis of delivered load to determine whether they continue to adequately contribute to the cost of service if they were billed on that basis. Any mismatch between the value of exported energy and the credit received under NEM is a question of whether the compensation for exports is appropriate. I conclude in my Section II analysis that there is not a significant mismatch in compensation and value when the analysis is conducted under a long-run timeframe that is appropriate for assessing resource value.

Q. Did you perform an analysis to demonstrate the contribution of residential NEM customers to the class cost of service with the value of export credits excluded?

A. Yes. I calculated the contribution that NEM customers within the residential class would make toward their cost of service if billed based on delivered load in two distinct steps. The first step was to determine the value of the NEM credits residential solar customers currently receive for their exported generation. The second step was to add back in the value of exported generation that the Company attributes to the production function of the class in the Actual Cost of Service NEM Breakout study.

From data request Vivint DR 2-34(a), I took aggregated data for the monthly percentages of NEM bill credits that fall into each of the three usage tiers for Schedule 1.

Table 1: Aggregate NEM Credit Data Derived from Vivint DR 2-34a[4]

Winter		
Month	**<= 400 kWh**	**>400 kWh**
1	17%	83%
2	26%	74%
3	30%	70%
4	41%	59%
10	36%	64%
11	42%	58%
12	30%	70%

Summer			
Month	**<= 400 kWh**	**401-1,000 kWh**	**>1,000 kWh**
5	43%	38%	19%
6	32%	39%	29%
7	21%	34%	45%
8	24%	38%	38%
9	25%	39%	36%

I applied these percentages to the monthly exported kWhs for the Residential class[5] to estimate the amount of exported kWhs that would fall into each usage tier.

Table 2: Exported kWhs Allocated to Each Usage Tier[6]

	Exported kWh	Tier 1	Tier 2	Tier 3
1	303,134	51,591	251,542	
2	601,625	157,190	444,435	
3	1,196,131	361,494	834,637	
4	1,538,529	634,923	903,606	
5	1,426,773	612,707	542,567	271,499
6	2,050,633	661,392	800,586	588,655
7	1,520,579	324,880	517,828	677,871
8	1,734,417	416,934	653,790	663,694
9	1,275,014	317,030	502,475	455,509
10	1,652,685	590,430	1,062,255	
11	1,621,222	681,847	939,375	
12	1,040,225	312,011	728,214	
Total	15,960,967			

Once the exported kWhs were allocated to the appropriate month and tier, I multiplied each by the corresponding retail rate under Schedule 1. This results in an estimate of the bill savings associated with exported generation: $1,738,520. By adding

[4] Vivint Data Request to Rocky Mountain Power, Set 2, Q.34.
[5] Monthly exported kWhs come from Exhibit: Steward – UT NEM Blocking 2015; *kWh-month* tab.
[6] Steward Workpaper - UT NEM Blocking 2015.xlsx (‘*kWh-month*’ tab).

this value to RMP's calculated revenue collected from solar customers ($2,778,025)[7], I found that if solar customers were billed based on delivered load, and did not receive NEM bill credits for exported generation, they would contribute $4,516,544 in revenue.

To compare this revenue to the cost to serve residential solar customers, I took RMP's result from the ACOS NEM Breakout Study ($4,585,118)[8], and modified it to account for the fact that the Company attributes some value to those exports, which it nets out against the production-related costs. The calculated value of this generation can be found on the 'Excess NEM Value' tab in the ACOS NEM Breakout file. I zeroed out that value in cell O14 ($382,047) and input the new revenue from the Residential NEM class on the 'Revenue' tab in cell X7. After allowing each of those values to flow through the model, the new cost of service for the Residential NEM class $4,928,476.

Q. What did you conclude from your analysis?

A. By comparing the hypothetical revenue that would be collected from customers billed based on delivered load to the full cost to serve that delivered load, I determined that residential solar customers under such a framework would contribute 91.6% of their cost of service without making any modifications to the Company's assumptions and calculations in its studies. The details for this calculation can be found in my "COS Parity on Delivered Load" workpapers.

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[7] Exhibit RMM-12, Column C, Line #2.
[8] Exhibit RMM-12; Column F, Line #2

Table 3: Cost of Service Parity Based on Delivered Load

Value of exported bill credits	$	1,738,520
Current Revenue from Resi NEM	$	2,778,025
Sum (hypothetical revenue based on delivered load)	$	4,516,544
COS for Resi NEM from ACOS NEM Breakout	$	4,572,456
COS from ACOS Breakout without attributing value to exports	$	4,928,476
Contribution to COS of delivered load:		**91.6%**

Q. You state that this result is based on the Company's unmodified analysis, without any changes to its input assumptions or calculations. Are there any assumptions in the Company's COS model that would change this result?

A. Yes, there are a number of assumptions that the Company makes in the model about how costs should be allocated to the Residential NEM class. A change in any of these assumptions could change the allocation, and thereby change the percent that NEM customers are contributing toward that allocated cost to serve.

Q: Can you point to any examples of cost allocation choices that you disagree with?

A: Yes. One example is the basis for allocating distribution line transformer costs. These costs are allocated based on each class's maximum monthly non-coincident peak (NCP). In the ACOS NEM Breakout study, the highest monthly NCP for the Residential class is in July, so the July peak is used to apportion its share of line transformer costs. The Residential NEM class, on the other hand, peaks in December, and therefore the Residential NEM class is apportioned its share of line transformer costs based on the December NCP. However, the December NCP would not be the most accurate reflection of what really drives line transformer costs. When NEM customers are not broken out, the residential class still has its max NCP in July. NEM customers continue to be on the same types of distribution circuits that they were before they installed solar. Furthermore, NEM customers continue to share the final line transformer with 4.12[9] other customers according to the Company's ACOS Breakout Study, and most of those, given the low penetration of solar, are not likely to also be NEM customers. Yet in the NEM Breakout Study, these customers now have their December NCP as the basis for cost allocation while the majority of customers they are likely to share the transformer with have costs allocated based on the July NCP, despite the fact that the load on their distribution circuit, and possibly at their shared transformer itself, would continue to most likely peak in July. In other words, the month which drives this cost category does not fundamentally change when customers choose to install solar because it is shared infrastructure where the load that drives the costs likely continues to peak in the same month.

Q: What would the impact be of basing Residential NEM cost allocation for this category on July NCP instead of December NCP?

A: I tested the impact of this change by making one simple edit in the cell reference on the 'Dist. Factors' tab of the ACOS NEM Breakout Study. Cell E29 references the December NCP for the Resi NEM class. I changed this to reference the July peak (cell J228), the month when the rest of the residential class experiences its max NCP. After flowing this change through the model, the COS parity increase from 91.6% to 95.7%. This is a result of having a $209,872 lower allocation of line transformer costs assigned to them.

[9] ACOS NEM Breakout Study; 'Dist. Factors' tab

Table 4: COS Parity with Additional Line Transformer Adjustment

Value of exported bill credits	$	1,738,520
Current Revenue from Resi NEM	$	2,778,025
Sum (hypothetical revenue based on delivered load)	$	4,516,544
COS from ACOS Breakout: Additional Line Transformer Adjustment	$	4,718,604
Contribution to COS of delivered load:		**95.7%**

Q: Are there any cost allocation factors used to allocate costs to NEM customers that could be driven by factors correlated with the fact that they are NEM customers, but not necessarily caused by that fact?

A: Yes. An example of a cost allocation choice driven by correlation, and not causation, is the "Coincidence Factor" involved in the allocation of line transformer costs. First, it is worth considering that net metering customers are overwhelmingly associated with single-family homes. Intuitively, there are certain cost characteristics that are likely to be different between single-family homes and service to multi-family structures like residential apartment buildings or facilities. For example, the average number of customers per transformer is fewer for customers in single-family homes than the average of all residential customers, which includes accounts associated with apartments, multi-family housing, and single-family structures[10]. Because the majority of NEM customers are in single-family homes, and because customers in areas with a majority of single-family homes would tend to have fewer customers per line transformer, one would expect that NEM customers are associated with fewer customers per transformer: not because of anything related to their status as solar customers, but rather because of the prevalence of single-family homes within this subset of the residential class.

[10] *See* Steward Direct at p. 16, Table 4.

These expectations are confirmed in the ACOS NEM Breakout Study where the Residential NEM class has 4.12 customers per transformer, while the rest of the residential class has 6.34 customers per transformer. These differences are driven more by the fact that most NEM customers have single family homes rather than multi-family or apartments, and not by any fundamental difference in how solar customers drive infrastructure costs

Q: How does the choice of coincidence factor impact the costs that get allocated to the Residential NEM class in the ACOS Breakout Study?

A: The coincidence factor is used in the allocation of these costs to account for the fact that customers that share a given transformer do not peak at exactly the same time, and that level of coincidence tends to decrease as the number of customers that share a transformer increases. As described in Pacificorp's guidance document for sizing residential transformers:

> *"Coincidence factors are applied when more than one customer is served by a single transformer or set of conductors. Since all customers generally do not reach peak load at the same moment, the total load on cables or on the transformer is generally less than the sum of the individual peak loads. Coincidental peak demand is determined by adding up the individual peak demands and multiplying by a coincidence factor."* [11]

When NEM customers are broken out, the coincidence factor is .82, based on the estimate that there are 4.12 customers per transformer among NEM customers. For the residential class as a whole, the value is .76, based on the estimate of 6.34 customers per transformer[12]. The guidelines for coincidence factors associated with each increment of

[11] Attachment to Vote Solar Data Request 1.49: "DA 411 General—Residential Electrical Demand".
[12] ACOS NEM Breakout Study; 'Dist. Factors' tab, Cells E31 and 31.

customers per transformer come from this table of guidance document referenced above[13]:

DA 411 General—Residential Electrical Demand

Table 1—Summer Peaking, Single-Family, Ducted Heat Source: Gas, Heat Pump, Other
Estimated Peak Demand (kVA) per Residence

Home Size (Effective/Total ft.²)		< 1300 ft.²		1300-2000 ft.²		2001-3500 ft.²		3501-4500 ft.²		4501-6000 ft.²	
Number of Customers	CF	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size	Peak Load	XFMR Size
1	1	8	**25**	10	**25**	14	**25**	17	**25**	22	**25**
2	0.9	15	**25**	18	**25**	26	**50**	31	**50**	40	**50**
3	0.86	21	**25**	26	**50**	37	**50**	44	**50**	57	**75**
4	0.82	27	**50**	33	**50**	46	**50**	56	**75**	73	**75**
5	0.78	32	**50**	39	**50**	55	**75**	67	**75**	86	**100[1]**
6	0.76	37	**50**	46	**50**	64	**75**	78	**100[1]**	101	**167[1]**
7	0.74	42	**50**	52	**75**	73	**75**	89	**100[1]**	114	**167[1]**
8	0.72	47	**50**	58	**75**	81	**100[1]**	98	**100[1]**	127	**167[1]**
9	0.71	52	**75**	64	**75**	90	**100[1]**	109	**167[1]**	141	**167[1]**
10	0.7	56	**75**	70	**75**	98	**100[1]**	119	**167[1]**	154	**167[1]**
11	0.7	62	**75**	77	**100[1]**	108	**167[1]**	131	**167[1]**	170	*
12	0.7	68	**75**	84	**100[1]**	118	**167[1]**	143	**167[1]**	185	*
13	0.7	73	**75**	91	**100[1]**	128	**167[1]**	155	**167[1]**	201	*
14	0.7	79	**100[1]**	98	**100[1]**	138	**167[1]**	167	**167[1]**	216	*
15	0.7	84	**100[1]**	105	**167[1]**	147	**167[1]**	179	*	231	*
16	0.7	90	**100[1]**	112	**167[1]**	157	**167[1]**	191	*	247	*
17	0.7	96	**100[1]**	119	**167[1]**	167	**167[1]**	203	*	262	*
18	0.7	101	**167[1]**	126	**167[1]**	177	*	215	*	278	*
19	0.7	107	**167[1]**	133	**167[1]**	187	*	227	*	293	*
20	0.7	112	**167[1]**	140	**167[1]**	196	*	238	*	308	*

This essentially implies that the coincidence of peak load among the 4.12 customers per transformer which includes the solar customers is higher. In other words, it implies that load diversity on the transformer decreases when one of the customers is a solar customer.

This is the opposite of what one would actually expect to happen. In fact, having a solar customer as one of the 4.12 customers on a given transformer would likely increase load diversity, thereby reducing the coincidence of the individual customer peaks and

[13] *See* RMP Response to Vote Solar data request 1-49, attached as Exhibit EG-2.

reducing the total peak load on the equipment. This would therefore justify a lower coincidence factor to account for the fact that those customers peak at different times.

To account for this mismatch, I applied the average coincidence factor for the residential class as a whole (.76) to the NEM subset of customers. In reality, the coincidence factor could be even lower than .76, which is the value from the table above associated with six customers per transformer. The impact of this change is an additional increase in the COS Parity percentage to 96.3%, higher than the average for the residential class as a whole (96.00%).

Table 5: COS Parity with Additional Coincidence Factor Adjustment

Value of exported bill credits	$	1,738,520
Current Revenue from Resi NEM	$	2,778,025
Sum (hypothetical revenue based on delivered load)	$	4,516,544
COS from ACOS Breakout: Additional Coincidence Factor Adjustment	$	4,690,503
Contribution to COS of delivered load:		**96.3%**

Q: Do you have any additional observations related to how line transformer costs are allocated?

A: Yes. It is also worth noting that the overall allocation to Resi + Resi NEM in the ACOS NEM Breakout Study is higher than the allocation to the Resi class as a whole in the ACOS Study when NEM customers are not broken out. The residential class is allocated 60.4454% of line transformer costs in the ACOS vs. 60.5216% when the broken out NEM customers are summed with the remaining residential customers. This is driven by the fact that some of the load diversity within the residential class as a whole is lost when a certain subset of customers is broken out. This leads to a higher total allocation of costs than the same customers would receive when taken together as part of the same class.

The fact that some customers within a class peak at different times or within different months is a good thing, leading to higher infrastructure utilization, and putting less strain on these assets during peak periods. Load diversity also helps reduce the need for incremental upgrades when compared to a situation where all customers peaked at the same time.

Q: What do you conclude after examining the impact of these adjustments?

A: It's clear that the Company has made a number of assumptions in their studies, and that reasonable adjustments to those assumptions can have a significant impact on the results. I believe there is a strong basis for making the two minor adjustments above, and even those two simple changes can bring the COS parity to the same level as the residential class overall in the ACOS study. To the extent other parties find additional reasonable adjustments, this value could change even more.

Q. Do these results support the Company's rationale for creating a separate class for residential customers that engage in behind-the-meter self generation?

A. No, for several reasons. First, from the perspective of ratepayer equity (i.e., that NEM customers are failing to cover their cost of service and shifting those costs in a significant way to other customers in the class), the Company's COS analysis fails to demonstrate a basis for creating a separate customer class. If customers with self-generation are continuing to provide approximately the same contribution to the class cost of service as average residential customers without self-generation, there is no basis for concluding that intra-class cost shifting exists. In fact, when appropriate adjustments are made to the Company's analysis, customers with self-generation contribute at least the same amount towards their cost-of-service as residential customers without self-generation.

Second, as a matter of ratemaking principle, the creation of separate rate classes is generally discouraged in the absence of clear cost-of-service justification for grouping similarly situated customers into their own rate class. Strictly speaking, each customer has its own distinct cost of service, so it is normal for there to be some amount of variation within a class of customers. For example, if different subsets of residential customers from the load research study were to be analyzed separately from the rest of the class (strata 1 customers for example), one might find that the cost of service parity for those customers is lower than the average for the rest of the class. Strata 5 customers, on the other hand, might contribute more than their cost of service. However, even if this were true, it would not necessarily be a justification for separating each strata into a separate class. Minor differences among the cost of serving various customers are typically disregarded in favor of minimizing the classes of customers for ratemaking and billing purposes.

Finally, the Company's comparison between the cost characteristics of net metering customers and the average residential customers fails to provide sufficient information to determine whether certain cost characteristics are driven by customers that specifically engage in net metering or whether the cost differences merely reflect the inherent differences between single-family and multi-family dwellings. As described above, the differences in cost allocation to solar customers for certain cost categories could be attributable more by differences between single family and multi-family homes, rather than any unique characteristics of solar customers themselves. The Company does not establish that net metering customers are so far outside of the normal variation within the residential class that they must be separated into a sub-group.

Q. Even if there were differences in the cost to serve residential net metering customers, should they be placed in a separate class?

A. No. As I have explained, some differences in cost to serve are likely more symptomatic of differences between single-family and multi-family dwellings than they are about NEM and non-NEM customers. If the Commission were to create a unique class or sub-class for each identifiable grouping with unique usage profiles—or with unique average demand or load factor—there could be an endless number of micro-classes created. My analysis shows that, on the basis of delivered load, net metering customers continue to fall very close to the average residential customer's contribution to the cost of service under the Company's analysis and may actually exceed the average residential customer when reasonable adjustments are made to cost allocations. If the Commission takes steps to adjust the compensation for exported energy, such an action could be accomplished without segregating net metering customers into a separate class and rate structure.

II. Valuation of Exported Energy

Q. Does the Company provide a valuation for exported energy for NEM facilities?

A: Yes, but in a very narrow sense. In the ACOS NEM Breakout Study, the Company calculates a value for NEM exports, which can be found in the *ACOS UT Dec 2015 NEM Breakout.xlsx* file on the 'Excess NEM Value' tab. The included benefits are limited to net power costs and line losses. These benefits are netted against the production-related cost of service.

Q. Does the Company's valuation fully and accurately capture the quantifiable value of exported energy for NEM facilities?

A: No. While the Company seems to have complied with the Order defining the type of analysis they were required to provide, the approach taken does not fully capture the value of exported energy. Additional value can be realized from solar generation to avoid or defer generation capacity, distribution and transmission infrastructure, among others. None of these additional value categories were quantified in the Company's assessment.

Q. Did you quantify the value of exported energy for NEM facilities?

A. Yes. In the following sections I describe the methodology for calculating each of the long-term value categories I evaluated. Within the long-run avoided cost framework, I look at the following categories of value: long-run energy, losses and CO_2 value; avoided generation capacity; and avoided transmission and distribution (T&D) costs.

<u>**Long-term Value of Exported Energy**</u>

Q. Why is it important, in the context of solar, to take a long-term view of the value of exported energy from NEM facilities?

A. One of the fundamental shortcomings of relying on changes in jurisdictional allocations in the various COS perspectives is that these approaches are incapable of accounting for a resource's ability to reduce overall system costs. The reduction in jurisdictional allocation to Utah attributable to NEM generation demonstrates the change in how costs are allocated (i.e., how the pie is sliced), but it fails to show how NEM generation affects overall system costs (i.e., reducing the size of the pie that is shared). For example, take the costs that are allocated based on contribution to coincident system peak. If every region within PacifiCorp's territories had the same level of penetration of NEM generation, and therefore contributed to reducing coincident system peak to the same extent, then the benefit associated with jurisdictional allocation would be zero in all areas. Despite the fact that these assets collectively reduce the system-wide peak load upon which infrastructure investment decisions are made, the jurisdictional allocation framework would not be capable of accounting for those benefits.

Q. In light of the Commission's current analytical framework for examining the costs and benefits of the net metering program, what is the purpose of examining the value of energy exports?

A. The framework provides an important snapshot as it relates to the current net metering program. However, the COS approach in Section I shows that customers with some onsite consumption of solar are contributing a vast majority of the cost of serving those customers. The rate structure for purchases from the utility does not create an inherent under-recovery from net metering customers. Looking at the long-term value of exported energy against the value that is assigned to the exports by the net metering program gives the Commission an additional view of whether subsidization occurs with the current model of compensation for energy exports.

Q. Are you recommending an alternative mode of compensating energy exports?

A. No, not at this time. I am presenting this analysis because it is helpful to compare the actual value of energy exports to the credit received by customers for those energy exports (i.e., the full retail volumetric rate) in understanding the long-term impact of the net metering program. This provides the Commission information, in addition to the various cost-of-service perspectives in the analytical framework, that is relevant and germane to the utility system cost impacts (i.e., long-run benefits) of customer generation. This is similar to the analysis that the Company performs in its integrated resource planning (IRP) dockets.

Q. Is your analysis based on the Company's IRP values?

A. To the extent data from the Company's IRP was available, I made an effort to include it. Where Company-generated data was not available, such as avoided T&D marginal costs, I calculated marginal costs using standard industry approaches. This is discussed for each category below.

Q. Based on your analysis, what is the long-term value of energy exports for NEM facilities on the Company's system?

A. As shown in Table 6, below, the levelized value of NEM energy exports is $0.1257/kWh. In contrast, the average credit amount for an exported kWh is approximately $0.106/kWh.[14]

Table 6: Summary of Benefit Valuation Results

Type	Benefit and Cost Category	Cents/kWh
Benefits	Energy	3.95
	Losses	0.38
	Future CO2 Compliance	0.29
	Generation Capacity	3.24
	Transmission Capacity	2.94
	Distribution Capacity	1.78
	Total Benefits	**12.57**

Q: Is this list comprehensive of all benefits that rooftop solar can provide?

A: Not necessarily. There are a number of potential benefits that I did not focus on in my analysis, such as fuel hedging, local economic development, and the ability to provide grid

[14] Steward Direct at p. 30, line 582.

services through smart inverter capabilities. Each of these categories could be quantified and added to the values that I calculated.

<u>Long-run Energy, Losses, and CO_2 Value</u>

Q. How did you determine the long-run value of energy, losses, and CO_2 compliance for exported energy?

A. For each of these benefit categories, I generated a levelized $/MWh value that was based directly on the long-term forecast from Pacificorp's 2017 IRP.[15] I levelized these values based on a discount rate of 6.57%, which is the after-tax weighted average cost of capital (WACC) used in the 2017 Pacificorp IRP.[16]

[15] Energy Price Forecast based on Average of Mid C/Palo Verde Flat Power Prices (Figure 1.5); Losses based on RMP's assumed average loss factor of 9.5%; CO2 prices based on Figure 7.22.

[16] As noted by Pacificorp, the use of after-tax WACC to discount all future resource costs complies with PUC of Oregon's IRP guideline 1a: Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

Table 7: 20-Year Value of Energy, Losses and CO_2 Compliance for Exported Energy

	Source: IRP Forecast	Source: RMP COS	Source: IRP Forecast		
	Energy	Losses	CO2 Cost		
Year	$/MWh		$/Ton	$/MT	$/MWh
2017	28.00	2.66	-	-	-
2018	28.00	2.66	-	-	-
2019	28.00	2.66	-	-	-
2020	29.00	2.76	-	-	-
2021	30.00	2.85	-	-	-
2022	34.00	3.23	-	-	-
2023	38.00	3.61	-	-	-
2024	40.00	3.80	-	-	-
2025	42.00	3.99	4.75	4.31	1.71
2026	43.00	4.09	6.81	6.18	2.46
2027	45.00	4.28	8.88	8.05	3.20
2028	48.00	4.56	10.94	9.92	3.95
2029	49.00	4.66	13.00	11.79	4.69
2030	50.00	4.75	26.00	23.59	9.39
2031	52.00	4.94	27.50	24.95	9.93
2032	53.00	5.04	29.00	26.31	10.47
2033	55.00	5.23	30.50	27.67	11.01
2034	57.00	5.42	32.00	29.03	11.55
2035	58.00	5.51	35.00	31.75	12.64
2036	59.00	5.61	38.00	34.47	13.72
Levelized $/MWh				-	-
(2017-2036)	***39.50***	***3.75***		-	***2.05***

Q. Would you consider these values conservative?

A. Yes. The forecast on which this levelized value is based uses estimates of the price of market purchases at two major power trading hubs averaged across the entire year. With respect to the value of energy delivered by solar, this is conservative for two reasons. First, solar generates primarily during the higher-cost high load hours of the day. An annual average will lose the variation between daily on-peak and off-peak prices. Second, solar generation is concentrated in the summer months when power prices are typically at their highest. Using an annual average flat price fails to capture this seasonal variation. Despite this lack of precision, I felt it was appropriate to calculate a conservatively low value using data directly from the IRP.

Q. How did you calculate losses?

A. I used the Company's estimate of 9.5%. I applied this to each of the annual average energy prices and levelized it in the same manner. Because the value for losses is based on the value of energy, the losses calculation is similarly conservative for the same reasons.

Q. How did you calculate a value for avoided CO_2 emissions?

A. I also took a conservative approach to calculating the $/MWh CO_2 value. I started with the Pacificorp forecast of CO_2 compliance prices from the Company's IRP. It should be noted that these are not societal benefits or estimates for avoided damage caused by CO2 emissions. Instead, this is the anticipated avoided compliance cost under future regulatory regimes that Pacificorp expects in its Preferred Case. The IRP includes a $/Ton forecast of prices starting in 2025. To convert this price forecast into a $/MWh value, I needed to assume an average emissions rate for grid power. I chose a heat rate of 7,000 BTU/kWh, equivalent to an efficient combined cycle natural gas generator. This is significantly lower than the average heat rate of natural gas plants in the US, which was 7,878 BTU/kWh in 2015, as reported by EIA[17]. Given the significant amount of coal generation that the Company's CFCOS study determined would be displaced (which could have a heat rate well over 10,000 BTU/kWh), the avoided CO_2 compliance value could be significantly higher than what I calculate here.

<u>Avoided Generation Capacity</u>

Q. How did you determine the avoided generation capacity value for energy exports?

A. To calculate avoided generation capacity value, I performed my analysis in the following steps:

- Created a short-run and long-run capacity price forecast
- Determined a resource balance year to transition between short-run and long-term prices
- Discounted those capacity prices based on a peak capacity contribution factor for PV solar
- Converted that stream of discounted prices into a levelized per MWh value

Q. Does your approach to determining this value differ from the Company's assumptions in its 2017 IRP?

A. The majority of assumptions used to calculate capacity prices came directly from the IRP. The one assumption where I deviate is the assumed resource balance year, but I base my

[17] https://www.eia.gov/electricity/annual/html/epa_08_01.html.

rationale for a different balance year in the sensitivity cases that Pacificorp evaluated in its IRP.

Q. How did you develop short-run and long-run price forecasts for generation capacity?

A. In the short-run, capacity value is based on capacity contracts or on the fixed costs associated with keeping existing capacity in the market. In states with capacity markets, this can be estimated from market data or a survey of bilateral contract terms. Pacificorp does not have a capacity market, but existing plants in the Pacificorp fleet do have to cover going-forward fixed costs to continue operating. From the Pacificorp IRP data, I took the fixed costs from the plant with lowest value (a combined cycle unit without duct-firing capability), which was $34.61.[18] This number is consistent with the weighted average of recent capacity prices in the California market, for the years 2012-2016 as reported by the California PUC ($34.80/kW-yr). As described in the recent E3 Study on the Benefits of Pacificorp and California ISO Integration ("The E3 Study")[19], capacity freed up by DG solar in Pacificorp's Balancing Area (BA) could be sold into the California capacity market, so this value is also reasonable proxy for the capacity value within the Pacificorp BA. Given that both values are very close to one another, I chose to use the value consistent with Pacificorp's IRP to maintain as much consistency as possible with the Company's own recent assumptions.

To estimate long-run capacity value, I determined the net cost of new entry (net-CONE), which represents the annualized fixed cost for a new fossil power plant net of

[18] Pacificorp IRP at p.120, Table 6.2.
[19] https://www.caiso.com/Documents/Study-TechnicalAppendix-Benefits-PacifiCorp-ISOIntegration.PDF.

margins it could make in energy and ancillary services markets. For CONE, I used the costs of a new aeroderivative Combustion Turbine (CT) from Table 6.2 from the 2017 IRP[20]. Pacificorp estimates that the CONE for this CT would be \$172.28/kW-yr, which includes capital costs as well as fixed operations and maintenance costs[21]. I then used an estimate for net energy margins from the E3 Study of \$62/kW-yr , which is subtracted off the CONE to arrive at a net-CONE of \$110.28. Each of these values is escalated at the inflation rate within the IRP (2.2%) to arrive at a 20-year stream of annual values. I should also note that the E3 Study assumed net-CONE for a CT would be \$215/kw-yr, nearly double the \$110.28/kW-yr I assume here. Using E3's assumption instead of Pacificorp's would increase the capacity value of solar by approximately 80%.

Q. What is a Resource Balance Year and how does the determination of an appropriate RBY affect the valuation of resources such as net metering facilities?

A. Pacificorp BAs need to maintain an adequate supply of resources to meet projected peak load into the future, as well as an additional target planning reserve margin to account for load forecast uncertainty, atypical weather events, and unplanned outages. Pacificorp calculated its target planning reserve margin in its 2017 IRP to be 13%.[22] A Resource Balance Year (RBY) is the point in the future when available capacity will fall below the forecast demand plus planning reserve margin (i.e. 113% of projected peak load), and therefore new capacity will need to be built.

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[20] The E3 Study bases its net-CONE value on aeroderivative CT estimated by the CAISO in its Transmission Planning Process.
[21] 2017 IRP; p.104; Table 6.2.
[22] 2017 IRP Volume 2, Appendix I – Planning Reserve Margin Study.

The RBY is a key input into the long-term forecast of capacity prices. It designates the year in which the capacity price forecast transitions to the full long-run value (i.e. the net-CONE described above). I follow the approach in the E3 Study of creating a linear interpolation between the short-run capacity price and the net-CONE in the RBY.

Q. What RBY do you propose for forecasting long-term capacity prices?

A. I propose to use 2021 as the RBY in my analysis, while Pacificorp uses 2028 in the Preferred Case of it IRP.

Q. What evidence supports an RBY of 2021?

A. There are several factors that could pull the RBY earlier than 2028, and Pacificorp even evaluates some of them as sensitivities in its IRP process. First, there are plants within Pacificorp's BAs that are at risk of early retirement. Pacificorp evaluates this in one of its IRP scenarios: the Regional Haze Case 6: "endogenous retirement case". "Endogenous" in this case means that the model (System Optimizer) chooses which plants retire vs. which install required pollution controls based on economics, rather than relying on an "exogenous" set of input assumptions from outside the model. This case retires the Jim Bridger Unit 2 in 2021 (350 MWs), while it remains in the Preferred Case until 2028[23]. This is significant because it implies that this plant will likely retire in 2021 instead of investing in Selective Catalytic Reduction (SCR) equipment to comply with EPA's Regional Haze Federal Implementation Plan.

While Pacificorp's Regional Haze Case 6 goes further than its Preferred Case in evaluating the potential for coal retirements among Pacificorp's generation fleet, its

[23] Pacificorp IRP at p.201.

assessment is limited to evaluating the tradeoff between retiring vs. installing SCR for projects within its own portfolio. However, this case does not estimate retirements among plants outside its portfolio driven by wholesale market dynamics which favor cheaper natural gas generation. The prevalence of low cost natural gas will likely drive additional retirements for purely economic reasons. This additional driver of plant retirements, both within its own fleet and across the WECC, is not directly evaluated in the IRP. The one sensitivity that indirectly assesses this impact is the case where "Front-Office Transactions" (FOTs), or short-term firm capacity contracts, are reduced by 400MW. While Pacificorp doesn't point to a specific reason for why there may be more limited availability for these types of capacity products, one driver could be additional economic coal retirements across the WECC creating lower overall reserve margins and therefore lower availability of excess capacity for other BAs to provide to Pacificorp. Due to both of these factors, it is reasonable to consider an RBY earlier than 2028.

Q. What sources does Pacificorp rely on to assess WECC-wide supply adequacy?

A. Pacificorp uses several public sources, including WECC's 2015 Power Supply Assessment (PSA). However, it is important to note that the WECC PSA relies on retirements that have been announced by the plant owners, and does not assess the likelihood of plant closures that have not yet been announced. In its own words, WECC "does not speculate which units may retire due to environmental requirements or financial considerations. Therefore, only generating units that were reported with a planned retirement date are incorporated in these studies."[24]

[24] WECC 2015 PSA at p.10, *available at* https://www.wecc.biz/Reliability/2015PSA.pdf.

Q. Have there been any significant newly announced retirements since WECC released its 2015 PSA?

A. Yes. The owners of Navajo Generating Station (NGS), the largest coal plant in the WECC at 2,250MW, have recently announced their plans to close the plant when its current lease expires in 2019[25]. According to a recent study by the National Renewable Energy Laboratory (NREL), "Electricity produced at NGS is currently more expensive than electricity purchased on the wholesale spot market."[26] This closure was not included in the WECC's 2015 PSA, and will have a significant impact on both WECC-wide supply adequacy, and the amount of excess capacity available to Pacificorp in meeting its own resource adequacy target.

Q. In addition to WECC's 2015 PSA, does Pacificorp rely on other supply adequacy assessments?

A. Yes. The Company points to a 2014 assessment from the Northwest Power and Conservation Council which concludes that planned new generation should sufficiently cover resource shortfalls through 2019. However, a more recent assessment from the same organization highlights the potential for resource shortfalls by 2021. The 2016 Pacific Northwest Power Supply Adequacy Assessment for 2021 highlights several large coal retirements that have been announced (Colstrip 1&2, Boardman, Centralia 1) and will push supply below the region's reliability targets. The currently planned 550MW of new generation will not be sufficient to meet the 1,400MW capacity shortfall, and

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[25] http://www.utilitydive.com/news/utilities-vote-to-close-2250-mw-navajo-plant-largest-coal-generator-in-we/436222/.
[26] NREL November 2016: Navajo Generating Station & Federal Resource Planning: Volume 1: Sectoral, Technical, and Economic Trends, *available at* www.nrel.gov/docs/fy17osti/66506.pdf.

therefore a large amount of new generating resources or demand-side programs will be needed by 2021. The Council states that it "will reassess the adequacy of the regional supply next year, which undoubtedly will include additional planned resources". [27]

Q. In addition to these supply adequacy assumptions, do wholesale and natural gas market price trends support your assertion regarding the likelihood of earlier than expected coal retirements?

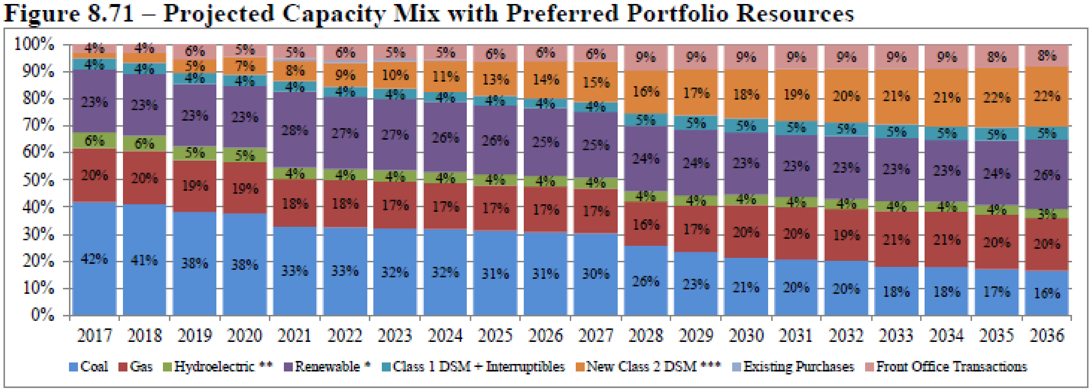
A. Yes. The NGS closure is just one example of a newly announced economic coal retirement, and more can be expected in the future. While the Company's IRP analysis refers to the regulatory uncertainty surrounding compliance with the Environmental Protection Agency's Regional Haze program and litigation regarding various State and Federal Implementation Plans under the Clean Air Act, market forces could play a much larger role than environmental requirements in determining the retirement dates for the Company's coal plants. Utilities are obligated to update their IRPs to reflect the most recent cost and market information, to determine whether it is cost-effective to continue operating coal plants or to invest in additional emissions reduction equipment (e.g., selective catalytic reduction, or SCR). However, the role of market forces, in the form of relatively low-cost natural gas (and the lower wholesale prices resulting therefrom), are not always evaluated in IRPs, as is the case with Pacificorp,

Q. To what extent does Pacificorp rely on the availability of excess capacity across the WECC to meet its supply adequacy target?

[27] https://www.nwcouncil.org/energy/resource/pacific-northwest-power-supply-adequacy-assessment-for-2021/.

A. Pacificorp's Preferred Case relies on increasing amounts of FOTs from outside its BAs to meet its resources adequacy needs. In this chart, you can see the FOTs grow from 4% of the capacity mix in 2017 to 9% in 2028[28]. That sharp increase will occur at a time when there is greater uncertainty with respect to the economic viability of a large amount of coal-fired generation across the WECC, particularly in UT, WY, and AZ.

Figure 8.71 – Projected Capacity Mix with Preferred Portfolio Resources



Given this increasing reliance on these short-term capacity transactions, Pacificorp evaluated a case limiting the availability of FOTs at two trading hubs: 100 MW at North of Oregon Border (NOB), and 300 MW at the Mona hub beginning 2021. These assumptions about reduced availability of FOTs correspond well with the timing of announced coal retirements highlighted by the NW Power and Conservation Council's assessment.

Q. What is the impact on RBY when combining the assumption that Jim Bridger 2 retires in 2021 and 400MW fewer FOTs are available?

A. Combining this reduction of 400MW in FOT availability with the Jim Bridger retirement in 2021 results in 750MWs less capacity in 2021 than in the Pacificorp Preferred Case.

[28] Pacificorp 2017 IRP at p.256.

By comparing this level of available capacity to the Peak Load + 13% Reserve Margin in the 2021 column of the Table 2.1 below[29], you can see that Pacificorp would face a resource shortfall in 2021 under this scenario.

Table 1.2 – PacifiCorp 10-Year Summer Capacity Position Forecast (MW)

System (Summer)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing Resource Capacity Contribution	10,493	10,494	10,109	10,194	10,069	9,980	10,062	10,043	9,920	9,912
Available FOT Capacity Contribution	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Total Existing Resource + FOTs	12,162	12,163	11,778	11,864	11,738	11,650	11,731	11,712	11,589	11,581
Obligation Net of Incremental DSM	9,730	9,743	9,743	9,758	9,793	9,824	9,829	9,850	9,892	9,831
13% Planning Reserve Margin	1,290	1,292	1,292	1,294	1,298	1,302	1,303	1,306	1,311	1,303
Obligation + 13% Planning Reserves	11,020	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135
System Position with Available FOTs	1,142	1,129	743	812	647	524	599	556	386	447
Reserve Margin with Available FOTs	25.0%	24.8%	20.9%	21.6%	19.9%	18.6%	19.4%	18.9%	17.2%	17.8%

Q. How did you determine the Peak Capacity Contribution percentage for solar PV?

A. I used the Peak Capacity Contribution for fixed-tilt solar in Pacificorp's Eastern Balancing Area (37.9%).[30] Pacificorp calculated this number by running a Loss of Load Probability (LOLP) analysis to determine hourly LOLPs. It then determined the level of coincidence between these hourly LOLP factors and the generation profile of solar PV. I used this Peak Capacity Contribution percentage to discount the annual values in the long-term capacity price forecast to account for the fact that each installed MW of solar is able to contribute 37.9% of its nameplate capacity toward meeting system peak load.

Q. How did you create a levelized $/MWh value from these annual $/kW forecasts?

A. I first converted the annual $/kW-yr value into $/MWh using the annual production of a typical solar PV profile from PVWATTS for Salt Lake City.[31]I then levelized the 20-year stream of annual values in a similar manner to the energy-related benefits based on a

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[29] *Id.*

[30] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.

[31] http://pvwatts.nrel.gov/.

discount rate of 6.57%, This resulted in a value of 2.73 cents/kWh, which I then grossed up by 13% to account for the fact reductions to peak load will reduce the basis for calculating the target PRM. In other words, every 1 MW of contribution to peak will reduce capacity obligations for the system by 1.13MWs. This resulted in a final value of 3.24 cents/kWh.

<u>Avoided Transmission and Distribution (T&D) Costs</u>

Q. Did the Company quantify any avoided transmission and distribution costs in its "Compliance Filing"?

A. They did not quantify any such benefits directly. They did include some transmission benefits based on the results of the Company's Jurisdictional Allocation Model (JAM). To the extent NEM generation reduces the basis upon which certain costs are allocated to Utah (like transmission costs allocated based on system coincident peak) the Company recognizes a small benefit attributable to NEM when comparing the ACOS results to the CFCOS results.

However, as discussed above, the reduced JAM allocation is only a small portion of the benefit attributable to NEM generation reducing transmission costs. Limiting the calculation to this approach implicitly assumes that system-wide transmission costs cannot be avoided or deferred, and instead, only the allocation of these costs can be shifted between Pacificorp's various service territories. In other words, the pie cannot get smaller, but the portion of the pie that Utah must pay for can change.

In contrast, I suggest that distributed solar generation can indeed avoid the need for incremental growth-related transmission capacity costs to the extent solar generation displaces load during the hours of highest system demand. By reducing peak load growth, capacity-related investments can be deferred or avoided. The long-run benefit of deferred and avoided transmission investments is much higher than the small differences in jurisdictional cost allocation that RMP has calculated.

Q. Are you aware of any real-world examples where demand-side resources have avoided or deferred significant transmission capacity expansion?

A. Yes. Reliance on "non-wires alternatives", including distributed solar, to avoid or defer conventional transmission solutions has been gaining wider acceptance in a number of jurisdictions.

- Brooklyn Queens Demonstration Project ($1B substation upgrade): Con Edison identified a potential 69.9 MW overload on subtransmission feeders which could mitigate a $1 billion investment in a new substation, switching stations and subtransmission feeders. As an alternative, Con Edison proposed procuring 52 MW of non-wires alternatives and 17 MW of traditional investments for $200 million, which would defer the need for a substation by several years. The non-wires alternative was approved, and Con Edison was authorized to amortize the costs of the program for 10 years;[32]
- In the CAISO, Pacific Gas & Electric canceled more than 13 previously approved low-voltage transmission expansion and distribution upgrades—at a savings of over

[32] New York Case No. 14-E-0302. Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program. Order Establishing Brooklyn/Queens Demand Management Program (December 12, 2014) at pp. 2-3.

$190 million—after distributed energy resources and energy efficiency obviated the need for the projects);[33]

- Also in California, a 230 kV transmission project in Fresno was deferred indefinitely due to local solar growth;[34]
- Most recently, Bonneville Power Administration has announced it will abandon its plan to build a new $1B transmission line along the I-5 corridor, and instead will pursue non-wires alternatives.[35]

Q. How did you develop the long-run benefit associated with avoided transmission?

A. I developed this number in the following way:

- Began by calculating a value for marginal transmission costs.
- Then determined hourly allocation factors for those costs, and determined the level of coincidence between solar generation and those factors. This resulted in a Peak Capacity Allocation Factor (PCAF) that I used to discount the total marginal cost value based on Solar PV's ability to displace load during the system's highest load hours.
- I applied the PCAF to the marginal costs and divided by the kWh generation per kW of installed solar to determine the per kWh avoidable transmission costs.

Q. How did you develop marginal transmission costs?

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[33] "Efficiency, Distributed Resources save California customers $192M", Robert Walton (June 1, 2016), *available at* http://www.utilitydive.com/news/efficiency-distributed-resources-save-california-customers-192m/420117/.
[34] "Solar growth puts Fresno high-voltage line on hold", Tim Sheehan, *Fresno Bee* (December 20, 2016), *available at* http://www.fresnobee.com/news/local/article122063189.html.
[35] https://www.greentechmedia.com/articles/read/a-non-wires-transmission-alternative-reflects-a-shift-in-grid-planning.

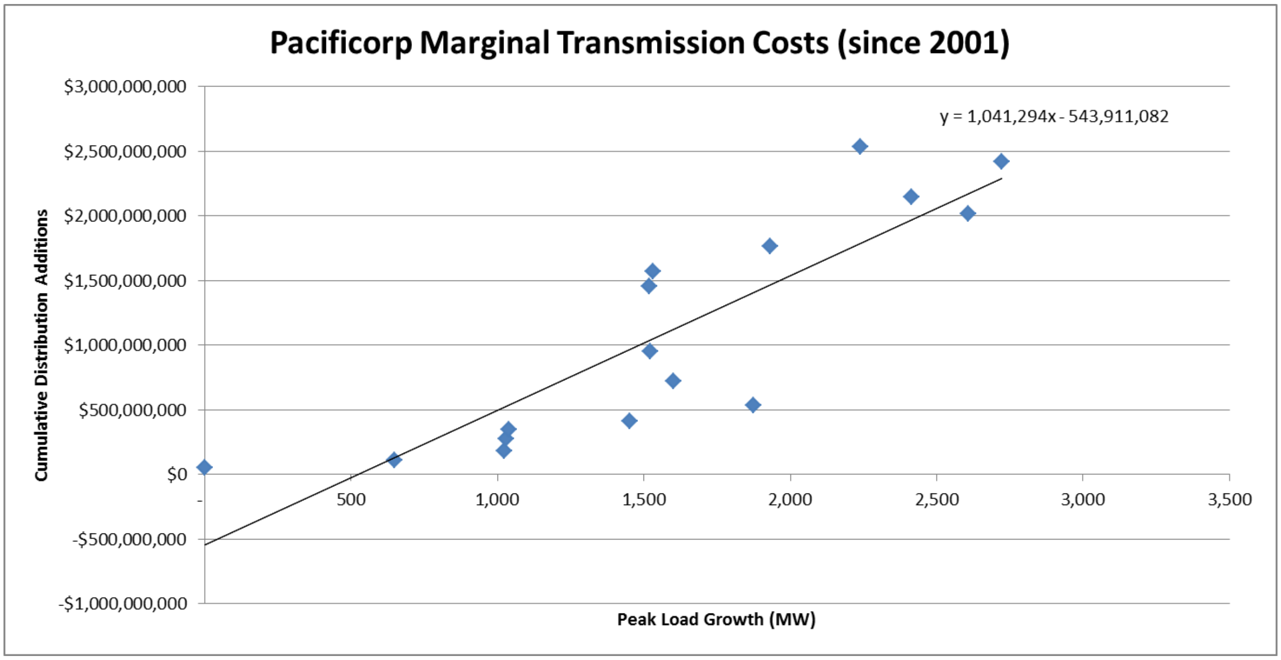
A. I used a long-standing methodology called the "Functional Subtraction Approach", which attempts to fit incremental growth-related transmission investments to peak load growth. This method is described in the NARUC Electric Utilities Cost Allocation Manual (1992)[36], and involves the following steps:

1. Determine annual growth in transmission costs over a specified period.
   - For this step, I used Pacificorp FERC Form 1 data for Transmission Plant Additions between 2001 and 2016.
2. Convert the investment data from Nominal Dollars to 2016$
   - I used historical inflation data from the Bureau of Labor Statistics to convert the historical nominal values into 2016$.
3. Determine what proportion of these investments is growth-related.
   - Pacificorp does not flag specific investments as growth-related. I therefore made a high-level assumption about which of the standard FERC Cost Accounts on the Form 1 should be considered growth-related, vs. which should not. I then calculated the subset of costs considered to be growth-related for each year in the analysis, and discounted the total additions by that percentage.
4. Determine the growth in transmission peak load.
   - I used annual transmission peak load data from the FERC Form 1.
5. Relate peak load growth to growth-related transmission investments.
   - To determine per kW transmission costs, I created a linear regression of cumulative load growth since 2001 to cumulative growth-related transmission

[36] pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD.

additions. The slope of the best-fit curve represents the change in growth-related transmission costs associated with each additional kW of peak load.

Figure 1: PacifiCorp Marginal Transmission Costs



6. Convert the per kW marginal cost into an annualized per kW-yr marginal cost
    - To create an annualized value, I apply an Annual Payment Factor (also called an Economic Carrying Charge) of 7.87%, which Pacificorp calculated as the annual factor for a new aeroderivative CT. While this number is not specific to transmission infrastructure, it is a reasonable proxy for investments that have a similar useful life (~30 years)[37].

At the end of these steps, I calculated the annualized marginal transmission costs to be $81.95/kW-yr.

Q. How did you determine solar PV's ability to avoid those marginal costs?

[37] Asset Class 49.13 (Electric Utility Steam Production Plant) has a useful life of 28 years, while Asset Class 49.14 (Electric Utility Transmission and Distribution Plant) has a useful life of 30 years, see https://www.irs.gov/pub/irs-pdf/p946.pdf.

A. I calculated a solar contribution percentage by developing hourly Peak Capacity Allocation Factors (PCAF) based on the highest load hours within one standard deviation of the absolute peak. Using hourly system load data from Confidential Data Response OCS 5.6-2 CONF to derive, I found the system peak to be 10,620 MW, with a standard deviation of 942 MW. I then determined which hours had loads above the threshold of (Peak – 1 Standard Deviation), summed the load above the threshold in those hours, and divided the load in each of those hours by that sum to create a set of hourly PCAFs that summed to 1 across the year. I then calculated a sum product of these hourly PCAFs with an hourly solar PV profile from PVWATTS.[38] This resulted in a solar contribution percentage of 57.1%.

Q. Based on these calculations, what is the per kWh avoided transmission value for distributed solar PV?

A. Based on a contribution percentage of 57.1% and a marginal cost of $81.95 per kW-yr, each installed kW of solar PV would have an avoided transmission value of .571*81.95 = $47.20 per kW-year. To convert to $/kWh, I divided by the annual production associated with the same PV profile from PVWATTS, which produced 1,607 kWh/kW, resulting in 2.94 cents/kWh.

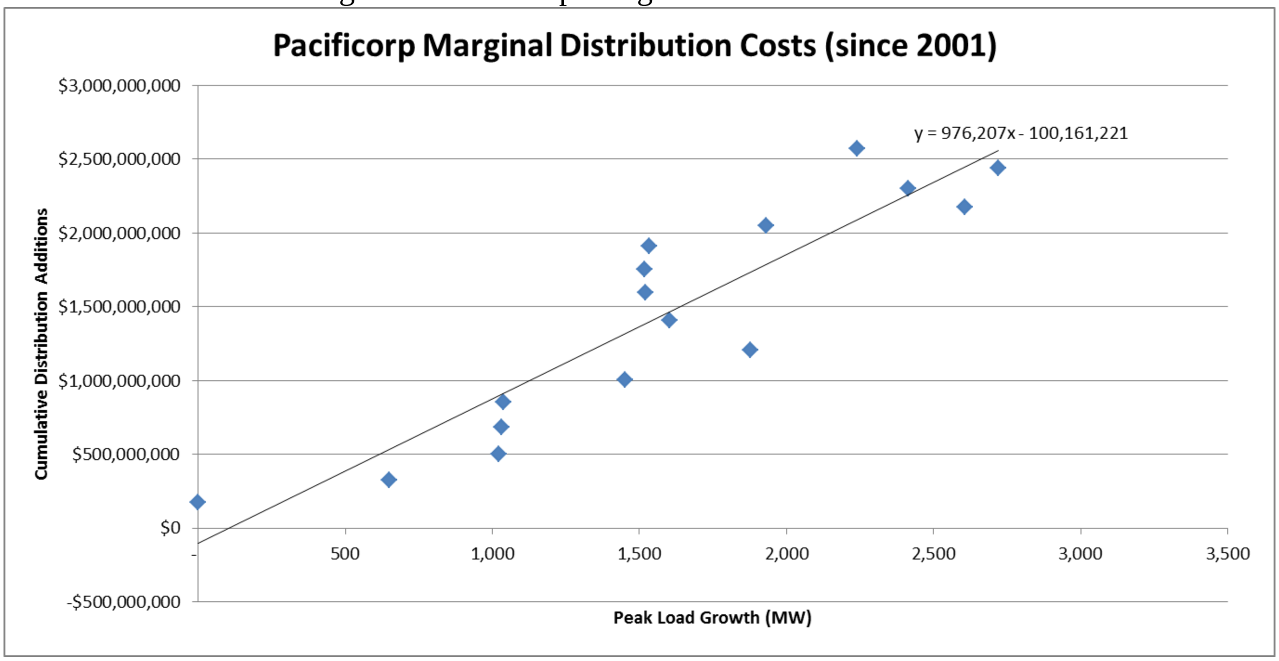
Q. How did you develop an avoided distribution cost for the Company's Utah distribution system?

A. I took a similar approach for marginal distribution costs. I took annual additions data from FERC Form 1, developed assumptions for which standard cost categories were growth-related vs. non-growth-related, discounted annual additions by that factor, and

[38] http://pvwatts.nrel.gov/pvwatts.php.

created a similar regression relating cumulative peak load growth to cumulative growth-related additions. The result of this analysis (i.e. the slope of the linear regression) was a marginal distribution cost of $976.2/kW.

Figure 2: PacifiCorp Marginal Distribution Costs



I created an annualized value using the same Annual Payment Factor of 7.87% to arrive at an annualized value of $76.83/kW-yr. I developed a similar PCAF value based on the distribution coincident peak loads in Data Response OCS 5.6-2 CONF, which resulted in a value of 37.14%. Discounting the full annual value by this amount and converting to a $/kWh value using the same PVWATTS profile, I arrived at a long-term distribution capacity value of 1.78 cents/kWh of solar generation. These calculations are documented in my confidential PCAF workpapers.

III. CONCLUSION AND RECOMMENDATIONS

Q. Do you have any recommendations for the Commission regarding the consideration of costs and benefits in this proceeding?

A. Yes. Acknowledging that the Commission will be using its analytical framework to investigate the costs and benefits of the net metering program, I recommend that the Commission consider additional perspectives to inform its long-term consideration of customer-sited generation and other distributed energy resources. My analysis shows that there are substantial benefits that are created by NEM facilities over the long run that are simply not captured in the Commission's primary analytical framework. Considering these long-run benefits gives the Commission a fuller record to consider whether specific changes to the net metering—which will necessarily have a long-term impact on the market for customer-sited generation facilities and other DER—are the most appropriate and are consistent with the overall policy goals of the state. Since customers that utilize solar generation to meet part of their onsite electricity needs would still pay their approximate cost of service if billed based on delivered load, it is important for the Commission to consider the net metering program in the proper context: as a means of valuing energy exports. Looking at the long-run value of NEM facility exports gives the Commission an apples-to-apples comparison (e.g., the long-run, levelized value of exports to the system vs. the level of credit received by customer-generators).

Q. Does this conclude your testimony?

A. Yes.