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

The Benefit-Cost Framework for Net Energy Metering

On Behalf of

Utah Clean Energy, The Alliance for Solar Choice, and Sierra Club

July 30, 2015

Table of Contents

List of Schedules

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 (Synapse) 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 attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Before rejoining Synapse, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). 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 implementation of decoupled rates for electric and gas companies; 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; a Manager at Tellus Institute; the Research Director at the Association for the Conservation of Energy; a Staff Economist at the Massachusetts DPU; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Master's 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 Schedule TW-1, presents additional details of my professional and educational experience.

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

A. I am providing evidence on behalf of Utah Clean Energy, the Alliance for Solar Choice (TASC) and the Sierra Club (together the "Joint Parties").

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the analytical framework that should be used to assess the costs and benefits of net energy metering (NEM) in Utah. My testimony also addresses the extent to which NEM might result in cross-subsidies between customers, which is one of the more important and challenging policy issues regarding NEM.

2. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your primary findings.

A. In order to assess the costs and benefits of NEM in Utah it is necessary to use two different sets of metrics:

- Cost impacts, in terms of cumulative present value of revenue requirements. This set of metrics indicates the extent to which NEM will reduce or increase electricity system costs and average customer bills over the long-term.
- Rate impacts, in terms of the percent change in rates. This set of metrics indicates the extent to which NEM will reduce or increase electricity rates over the long-term.

The cost impact metrics indicate the extent to which NEM will provide benefits to the electricity system as a whole, and are consistent with the benefit-cost analyses that utilities typically perform for assessing the impacts of supply-side resources and demand-side management (DSM) resources. The rate impact metrics indicate the extent to which customers who do not install photovoltaics (i.e., non-participants) will experience increased rates. The rate impact metrics can be seen as an indication of the extent to which NEM might create inequities between non-participants and participants.

I present an illustrative rate impact analysis to demonstrate how such an analysis can be performed for Rocky Mountain Power's (RMP or the Company) residential rate class. My rate impact analysis uses a fairly simple methodology and relatively high-level assumptions, in order to illustrate the approximate magnitude of rate impacts of NEM under several different conditions.

My rate impact analyses use a range of assumptions for two important variables: the amount of PV[1] penetration and the magnitude of avoided costs, as follows:

- Five Percent Penetration, where I assume that one-half percent of residential customers install PV each year for the ten-year period of 2015-2024, resulting in a total of five percent PV penetration by 2024.
- Ten Percent Penetration, where I assume that one percent of residential customers install PV each year for the ten-year period of 2015-2024, resulting in a total of ten percent PV penetration by 2024.
- Higher Avoided Cost, where I assume levelized avoided costs of $116/MWh.
- Lower Avoided Cost, where I assume levelized avoided costs of $60/MWh.

The results are summarized in Table 1. The year-to-year rate impact is an indication of how much residential rates would increase from one year to the next with the adoption of the assumed level of PV under NEM. The 10-year cumulative rate impact is an indication of the cumulative impact on residential rates of the assumed level of PV, relative to a case where no new PV resources were installed at all.

As indicated in Table 1, the rate impacts of NEM are likely to be relatively small, and possibly negative. The year-to-year rate impacts range from a reduction of 0.1 percent to

[1] Through the rest of this testimony, all references to PV will refer to behind-the-meter photovoltaics.

an increase of 0.3 percent, while the 10-year cumulative rate impacts range from a reduction of 1.5 percent to an increase of 3.3 percent. The rate reductions occur in those scenarios where the avoided costs are higher than the residential retail rate.

Table 1. Summary Results of Illustrative Rate Impact Analysis

Penetration Level	Avoided Costs	Year-To-Year Rate Impact	10-Year Cumulative Rate Impact
Five Percent Penetration	Lower Avoided Costs	0.2%	1.6%
	Higher Avoided Costs	-0.1%	-0.7%
Ten Percent Penetration	Lower Avoided Costs	0.3%	3.3%
	Higher Avoided Costs	-0.1%	-1.5%

It is not surprising that the rate impacts of NEM are likely to be very small, because the cost of the PV systems are paid for by the host customers. The PV generation is essentially a free resource to the utility system, and it is provided at a time when power costs are typically at their highest.

Q. Please summarize your recommendations.

A. I recommend the following:

- The Commission should approve an analytical framework consisting of two sets of metrics to indicate the costs and benefits of NEM in Utah: one set of metrics for cost impacts, and a separate set of metrics for rate impacts.

- The Commission should require that the cost impact analysis include all of the costs and benefits that are experienced by the utility system, and that are passed through to customers in terms of revenue requirements. This methodology is consistent with the Utility Cost Test that is used to screen DSM in Utah.

- The Commission should require that the rate impact analysis estimate the long-term percent change in customer rates resulting from NEM. The analysis should account for all the factors that cause either upward or downward pressure on rates. The rate impact analysis should also indicate the year-to-year rate impacts of NEM.
- The Commission should require the Company to prepare the cost impact analysis and the rate impact analysis, using the best available methodologies, inputs and assumptions.
- The Commission should find that the Rate Impact Measure Test (RIM Test) shall not be used to analyze the costs and benefits of NEM, because it suffers from several fundamental flaws.

3. TWO SEPARATE METRICS ARE NECESSARY TO EVALUATE NEM

<u>Cost Impacts Versus Rate Impacts</u>

Q. Why do you say that two separate sets of metrics are necessary to evaluate the costs and benefits of NEM?

A. A cost impact analysis is the standard technique used to assess the costs and benefits of electricity resources. Such an analysis typically involves comparing the cumulative present value of revenue requirements (PVRR) associated with the resource in question, with the cumulative PVRR of an alternative resource or set of resources.

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

Similarly, the Utility Cost Test used to evaluate DSM resources is a cost impact analysis. The costs of a scenario with DSM resources are compared to the costs of a scenario without DSM resources. The results of the cost impact analysis are presented in terms of net benefits (the difference in cumulative PVRR of the two scenarios) and a benefit-cost ratio (the ratio of cumulative PVRR benefits to cumulative PVRR costs).

However, NEM, like DSM, creates impacts on electricity rates as well as costs. This occurs because behind-the-meter PV, like DSM, will result in customers reducing their electricity consumption. As the utility’s sales are reduced, it may need to raise rates to ensure a proper recovery of its costs. A cost impact analysis cannot adequately capture this effect on customer rates. Yet this effect is very important, because it provides an indication of the extent to which customers who do not install PV will be affected by those who do. Therefore, a separate rate impact analysis is necessary in addition to the cost impact analysis.

Q. What analytical framework should be used for a rate impact analysis?

A. The key difference between the cost and rate impact analyses is in the units in which the outputs are presented. The cost impact analysis should provide results in cumulative PVRR. The rate impact analysis should provide results that put the rate impacts in context. This would include metrics such as the ¢/kWh change in rates, percent change in rates, or percent change in total bills.

Apart from outputs, the analytical framework for the rate impact analysis should be similar to that of the cost impact analysis. One or more scenarios with PV resources should be compared with a scenario without PV resources. The study period should be the same as the study period for the cost impact analysis, to capture the full long-term impacts. The same PV costs and avoided costs should be used in both the cost impact analysis and the rate impact analysis.

In fact, the two analyses should be performed as part of the same study, with consistent methodologies, inputs and assumptions. The key difference between the cost impact analysis and the rate impact analysis is in the presentation of the results: cost impacts should be presented in terms of cumulative PVRR; rate impacts should be presented in terms of ¢/kWh, percent change in rates, or dollars per customer per month. Additional details about the analytical framework for the rate impact analysis are provided in Section 5 below.

<u>The Rate Impact Measure Test</u>

Q. The Rate Impact Measure Test is one of the five standard tests used to evaluate DSM cost-effectiveness. Should the RIM Test be used for the rate impact analysis?

A. No. The RIM Test should never be used to evaluate the cost-effectiveness of either DSM resources or NEM, for several reasons: the logic underlying the RIM Test is flawed; the test provides no meaningful information for the Commission or stakeholders to understand the magnitude of rate impacts; the RIM will not result in the lowest costs to the utility system or to customers; and the RIM Test can lead to perverse outcomes where significant cost reductions are foregone in order to avoid negligible rate impacts.

Q. Why do you say that the underlying logic of the RIM Test is flawed?

A. The only difference between the RIM Test and the Utility Cost Test calculation is the "lost revenues" cost component (i.e., the reduction in revenues as a result of reduced consumption and fewer sales). If the utility is to be made financially neutral to the impacts of reduced consumption through DSM or NEM, then the utility should collect the portion of lost revenues necessary to recover its fixed costs. If the utility is to recover these lost revenues in rates, then this will cause upward pressure on rates.

To understand this issue it is critical to recognize that these lost revenues are the primary reason that long-term rates might increase as a result of DSM or NEM. If it were not for these lost revenues, then cost-effective DSM and NEM would generally cause long-term rates to be lower than they would otherwise be, because the utility system benefits outweigh the costs.

It is also critical to recognize that lost revenues are not a "new" cost created by the DSM or NEM programs. Lost revenues are simply a result of the need to recover existing costs from fewer sales. The existing costs that might be recovered through rate increases as a result of lost revenues are (a) not caused by DSM or NEM, and (b) are not a new, incremental cost. These existing costs are recovered from customers regardless of whether the future project is undertaken. In that way, they are unlike all the other program costs analyzed in the cost impact analysis. Therefore, these existing costs should not be included as part of the cost impact analysis.

As noted above, cost impact analyses typically include the comparison of one resource portfolio without DSM or NEM to an alternative resource portfolio with DSM or NEM.

The benefits and costs are identified by taking the difference between the two scenarios. The lost utility revenue will be recovered from ratepayers in both scenarios. It does not make any sense to include these costs in one of the scenarios but not the other, because these existing costs will be recovered from customers either way.

In fact, the results of the RIM test can be highly misleading. If the RIM Test results indicate that the net benefits (in cumulative present value dollars) of DSM or NEM are negative—in other words that the costs (including recovery of lost utility revenue) exceed the benefits—then this implies that the DSM or NEM program will increase costs. However, the "costs" that drive this result are the recovery of lost revenues that will be recovered from ratepayers under any future scenario, with or without the program. In other words, the RIM Test result suggests that costs will increase, when in fact they will not. For all programs that pass the Utility Cost test, actual costs will be reduced. For this reason, the results of the RIM Test should never be presented in terms of net benefits (in cumulative PVRR), because they are incorrect and misleading.

Q. Why do you say that the RIM Test provides no meaningful information for understanding the magnitude of rate impacts?

The RIM Test does not provide any information about what actually happens to rates as a result of program implementation. A RIM Test benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact, in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM Test results do not provide any context for utilities and regulators to consider the magnitude and implications of the rate impacts. What are the implications a RIM Test benefit-cost ratio of 0.98? How much are customers harmed by this result relative to a RIM benefit-cost ratio of 1.2? Significantly, the RIM Test cannot answer such important questions.

Q. Why do you say that the RIM Test will not result in the lowest cost to the utility system or customers?

A. Applying the RIM Test to evaluate DSM or NEM will not result in the lowest cost to customers. Instead, it may lead to lower rates (assuming all else being equal, the assumptions of the evaluation hold true, and the test is applied properly). However, achieving the lowest possible rates is not the sole or even the primary goal of utility planning and regulation; there are many goals that utilities and regulators must balance in planning the electricity system. Maintaining low utility system costs should be given priority over minimizing rates.

Q. Why do you say that strict application of the RIM Test can lead to perverse outcomes?

A. A strict application of the RIM Test can result in the rejection of significant reductions in utility system costs to avoid what may be insignificant impacts on customers' rates. For example, a DSM or NEM program might offer hundreds of millions of dollars in net benefits to the utility system, but be rejected as not cost effective with a RIM Test benefit-cost ratio of slightly less than one. It may well be that the actual rate impact, if calculated properly, is so small as to be unnoticeable. Rejecting large reductions in utility system costs to avoid *de minimis* rate impacts is clearly not in the best interests of customers overall.

Putting Rate Impacts in Perspective

Q. Please describe what you mean by putting rate impacts in perspective.

A. Increased rates from DSM or NEM raise customer equity concerns. It is often considered inequitable for non-participants to pay higher electric bills (as a result of higher rates), while participants typically experience lower bills.

To put these equity concerns in perspective, it is important to recognize the customer inequities that already exist in the regulated electricity industry. While it is important to minimize and mitigate undue customer inequity wherever possible, it is also important to recognize that customer inequity occurs in many ways in the regulated industry. For example:

- When a utility installs a new power plant to meet increasing electricity demands due to new customers or an increase in the use-per-customer, all customers pay for the new power plant. However, existing customers whose electricity demands have not increased in recent years do not directly benefit from that new power plant.
- When a utility installs a new transmission line for economic or reliability reasons, all customers typically pay for the new transmission line. However, many customers may not experience the reliability or economic benefits of the new line because they are not located in the affected areas.
- When a utility installs new distribution systems to serve a newly developed residential neighborhood or a new industrial park, all customers typically pay for the new distribution systems. However, many customers do not experience the benefits of the new systems because they are not located in the affected areas.

- The costs to provide transmission and distribution services to customers located in urban areas can be very different from the costs to provide these services to customers in rural areas. However, there is no distinction in the rates for these different customer types, potentially leading to significant inequities between them.
- The cost of electricity is much greater during times of peak demand, but most customer rates do not reflect this difference in cost. Consequently, there is typically some inequity between customers who use a lot of power during times of peak demand and those who do not.

Q. Why is it important to recognize that supply-side resources result in customer inequities?

A. It is critical to recognize these inequities in order to put equity concerns associated with NEM in perspective. With supply-side resources in general, it is very difficult to achieve a standard of ensuring absolutely no inequity among customers. It is not possible to build power plants, transmission lines, or distribution systems without some customers benefitting more than others. In this context, regulators and utilities have an obligation to balance the goal of minimizing customer inequities with the other goals of providing safe, reliable, efficient, low-cost electricity services.

The same concept applies to NEM. In order to obtain the various benefits of NEM, it is not possible or reasonable to achieve a standard of ensuring that there will be absolutely no inequity among customers. Applying the RIM Test to the NEM program would require that it meet this overly burdensome and inappropriate standard. Instead, regulators and utilities have the same obligation that they have for supply-side resources:

to balance the goal of minimizing customer inequities with the other goals of providing safe, reliable, efficient, low-cost electricity services.

Accordingly, NEM should not be held to the standard of creating no cross-subsidization when that standard is not applied to any other resource. This is especially true given that doing so can lead to perverse outcomes, as described above.

Q. Are the RIM Test concerns described above recognized by other states and other regulatory commissions?

Yes, essentially every state in the country has rejected the use of the RIM Test as the primary test to use for determining DSM cost-effectiveness. It should not be used for assessing the costs and benefits of NEM either, for the same reasons. Specifically, it should not be used for evaluating the rate impacts of RMP's NEM program under Utah Code Ann. Section 54-15-105.1.

4. THE COST IMPACT ANALYSIS

Q. Please describe the analytical framework that should be used for the cost impact analysis.

A. I recommend that the NEM cost impact analysis be based upon the same analytical framework as the Utility Cost test. There are several reasons for this recommendation:

- The Utility Cost Test is consistent with the scope of the benefit-cost framework as defined by the Commission, which found that the impacts to be included in this framework "must be a cost or benefit that has some impact on the utility's cost of service."[2] This is exactly what the Utility Cost Test does. It includes all of the costs and benefits that will eventually affect future revenue requirements, and therefore provides a clear indication of the costs and benefits to utility customers as a whole.

- The Utility Cost Test is consistent with the way that supply-side and demand-side resources are evaluated in IRP, where the preferred resource plan is determined primarily by minimizing the cumulative (risk adjusted) PVRR over the long-term.
- The Utility Cost Test is used as the primary framework for analyzing the cost-effectiveness of DSM resources in Utah. A collaborative report filed by RMP, the Utah Division of Public Utilities, and the DSM Advisory Committee recommended, among other things, that the Utility Cost Test be used as the threshold test in determining DSM program cost-effectiveness.[3] The Commission concurred with the report, and directed that DSM programs must pass the Utility Cost Test at a minimum.[4]
- The same collaborative report also recommended that small-scale renewable resources be evaluated on the same basis as DSM.[5] Again the Commission concurred with the report and directed the utility to evaluate small-scale renewable projects on

[2] 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, Order, issued July 1, p. 15.
[3] Utah Demand Side Management and Other Resources Benefits and Cost Analysis Guidelines and Recommendations, April 2009, p. 4.
[4] Public Service Commission of Utah, In the Matter of the Proposed Revisions to the Utah Demand Side Resource Program Performance Standards, Docket No. 09-035-27, Order, issued October 7, 2009, p. 11.
[5] Utah Demand Side Management and Other Resources Benefits and Cost Analysis Guidelines and Recommendations, April 2009, pp.5-6.

a similar basis as DSM. In addition, the Commission directed RMP to perform all five economic tests.[6]

Q. Which types of costs should be included in the cost impact analysis?

A. Again, the analysis should include all costs that will be passed on to customers in future revenue requirements. For NEM and PV this would include the following costs:

- The costs incurred by RMP to administer the NEM program, such as incremental metering or billing costs.
- The contribution made by RMP toward the cost of installing the PV system on the customer's premises, if any. It is my understanding that RMP does not currently offer financial support for PV installation under the NEM program, so this cost would be zero.
- The cost of providing customers who install PV with direct payments of NEM credits. It is my understanding that the Utah NEM program does not result in any direct payments of NEM credits to participating customers, so this cost would be zero.
- The incremental cost incurred by RMP to modify the local distribution system to allow for integration of PV on the system.

[6] Public Service Commission of Utah, In the Matter of the Proposed Revisions to the Utah Demand Side Resource Program Performance Standards, Docket No. 09-035-27, Order, issued October 7, 2009, p. 15.

Q. Which types of benefits should be included in the cost impact analysis?

A. Again, the analysis should include all benefits that will eventually be enjoyed by customers in terms of future revenue requirements. For NEM and PV this would include the following benefits:

- Avoided energy costs.
- Avoided capacity costs.
- Avoided transmission costs.
- Avoided distribution costs.
- Avoided cost of environmental compliance, including compliance with the U.S. Environmental Protection Agency's proposed Clean Power Plan under section 111(d) of the Clean Air Act.
- Avoided cost of complying with Utah's Renewable Portfolio Standard.
- Reduced risk, including reduced fuel price risk.
- Reduced transmission and distribution line losses.
- Any additional reduced grid costs as a result of PV power production.
- Reduced revenue requirements resulting from the NEM credits that remain at the end of the year and are used to provide assistance to low-income customers.

My colleague Ben Norris provides additional information on these costs and benefits in his testimony in this docket.

5. THE RATE IMPACT ANALYSIS

Analytical Framework

Q. Please describe the analytical framework that should be used to assess the potential rate impacts from net energy metering.

A. The analytical framework for the rate impact analysis should be very similar to that used for the cost impact analysis. It should use the same key assumptions, including the same costs and benefits of PV. The analysis should also include a scenario without PV and at least one scenario with PV, where the rate impacts are determined by comparing the two scenarios. The rate impact analysis should also use the same study period as the cost impact analysis, which should be long enough to capture the long-term impacts of the PV system.

As with the cost impact analysis, it will be necessary to make assumptions regarding the type and level of PV that might be installed, as well as the capacity (in MW) and energy (in MWh) reductions from the PV. This information will help indicate the magnitude of avoided costs (in dollars), as well as the amount that sales will be reduced by the PV.

Q. In what ways will the rate impact analysis be different from the cost impact analysis?

A. As noted in Section 3, the key element of the rate impact analysis is the presentation of the results, in terms of change in ¢/kWh, percent change in rates, dollars per customer per month, or some other metric to put the rate impacts in perspective. This requires making a forecast of electricity rates and sales for the duration of the study period. The cost impact analysis includes only forecasts of utility system costs under a set of different scenarios; the rate impact analysis includes forecasts of costs, rates and sales under that same set of scenarios.

The rate impact analysis should be conducted at the level of a rate class, because the impacts will be different across rate classes. It may not be necessary to conduct a rate impact for every rate class, as the impacts may be fairly similar across classes with similar rate structures.

The forecast of rates in the scenarios with PV should account for both the downward pressure on rates as a result of avoided costs, as well as the upward pressure on rates as a result of reduced sales. This can be achieved by calculating future rates as the ratio of future annual costs over future annual sales, in the scenarios with PV.

Once a forecast of future rates is prepared for the scenario without PV and the scenarios with PV, then the rate impacts are determined by taking the differences between the with and without scenarios. The rate impacts can be calculated in terms of ¢/kWh, percent change in rates, dollars per customer per month, or some other relevant metric.

Q. Are there other metrics that can be used to indicate rate impacts?

A. Yes. The rate impact results described above are based on two hypothetical scenarios: one without new PV and one with new PV. Customers will not actually observe these rate impacts because only one future scenario will take place. The purpose of comparing the "with" and "without" scenarios is to provide an indication of this difference – even though customers will never be aware of the difference. What customers will be aware of is the extent to which their rates change from one year to the next as a result of the additional PV.

For this reason, it is useful to also present "year-to-year" rate impacts. This metric uses the same information from the rate impact analysis, but focuses only on the change in rates from one year to the next in the scenario with PV. This rate impact metric is similar to the metric that is often used to describe the rate impact of a rate case. When a utility indicates that its rate request will result in a certain percent change in rates, it is presenting this increase in terms of year-to-year increases.

<u>Illustrative Rate Impact Analysis for Net Energy Metering in Utah</u>

Q. Please describe the purpose of conducting your illustrative rate impact analysis.

A. I present an illustrative rate impact analysis to demonstrate the analytical framework described above, and to indicate what the results of such an analysis might look like under several scenarios.

Q. Please describe how you prepared an illustrative rate impact analysis for net energy metering in Utah.

A. I developed a workbook model for this purpose. Exhibits TW-2 through TW-5 provide print-outs of the key elements of the workbook.

At the outset, it is important to recognize that my illustrative analysis is relatively simple, given the complexities of utility expenditures and ratemaking. I make several general assumptions using the best data that I have available at this time. The purpose of my analysis is not to forecast what the utility rates are likely to be over the long-term future. The purpose of my analysis is to (a) indicate the analytical framework that can be used to estimate the rate impacts of NEM; and (b) to provide transparent, first-order, high-level estimates of what the rate impacts might be under the methodology and assumptions used in the analysis.

The analysis is based on comparing forecasts of hypothetical future scenarios: one assuming that no new PV is installed over the study period, and others assuming a specified amount of PV is installed. For both scenarios, the analysis includes a forecast of utility sales, costs and rates for the study period. A comparison between a “Without-PV” scenario and a “With-PV” scenario reveals the difference in sales, costs and rates caused by the PV.

The model is structured to analyze the impact of net metering on retail customers over the next 20 years, starting in 2015. This analysis makes several simplifying assumptions. For example, it uses levelized avoided costs because I do not have more detailed avoided costs by year. The calculations are also based on the assumption that rates are adjusted every year to account for reductions in electricity sales as a result of the PV. In fact, the model is set up in such a fashion that RMP recovers all of its costs for a given year in that same year, such that for every year, costs and revenues are equal. In practice, there would be a lag of at least one year before the prices would be corrected to recover lost revenues. For these reasons, the results of any one year should not be taken in isolation, as the upward and downward pressures on rates might be different because of these temporal differences. Instead, the analysis should be used to assess general trends over the long-term.

Q. How are sales calculated in the Without-PV Scenario?

A. The model uses data from the Energy Information Agency's Form 861 to establish baseline residential sales (in megawatt hours), revenues (in dollars), and number of customers (count) for 2013.[7] It uses this data to calculate the average usage (in megawatt hours) per customer. The user can then input a customer growth rate and usage per customer growth rate. For my illustrative analysis, I input a customer growth rate of one percent and no growth rate in usage per customer. The model then estimates total number of customers and total usage between 2015 and 2024.

Q. How are rates calculated in the Without-PV Scenario?

A. Rates are assumed to remain the same as the current rates for RMP's residential customers, throughout the study period. All costs are in real dollars, i.e., excluding the effects of inflation. Therefore, this assumption means that in the Without-PV scenario rates will increase with inflation, but no more.

The energy portion of the rate is calculated using a weighted average of RMP's inclined block rates for summer and winter periods. The value is estimated to be 9.84 cents per kilowatt-hour. This is based on a customer that consumes 800 kilowatt-hours a month for both summer and winter months.[8]

[7] US Energy Information Agency, *Annual Electric Power Industry Report*, Form 861, 2013, http://www.eia.gov/electricity/data/eia861/.

[8] This is the average monthly consumption for residential customers, based on annual residential sales and number of residential customers.

Q. How are costs calculated in the Without-PV Scenario?

A. For this scenario costs and revenues are assumed to be equal to one another, and are based on the current rates, number of customers, and usage. The model calculates the amount of revenues that would be collected through the energy charge by multiplying sales by the energy portion of the RMP rate.

Q. What assumptions do you make about PV penetration in the With-PV Scenarios?

A. I assume two different penetration scenarios:

- Five Percent Penetration, where I assume that one-half percent of residential customers install PV each year for the ten-year period of 2015-2024, resulting in a total of five percent PV penetration by 2024.
- Ten Percent Penetration, where I assume that one percent of residential customers install PV each year for the ten-year period of 2015-2024, resulting in a total of ten percent PV penetration by 2024.

Q. How are sales calculated in the With-PV Scenarios?

A. In the With-PV scenarios, sales are set to be equal to the amount of usage in an annual year minus the amount of PV generation in that same year.

Q. How is PV generation estimated?

A. For a given year, the model calculates a number of customers with net metered PV and multiplies that by the estimated annual generation from an average PV installation in Utah, based on the National Renewable Energy Laboratory's PVWatts system.

Q. What assumptions did you make about avoided costs?

A. Given the importance of avoided costs in the analysis, I assume a range of avoided costs in two scenarios. In the Higher Avoided Cost Scenario, I use the avoided costs presented in a study prepared for Utah Clean Energy, which estimated that avoided costs from solar net metered facilities was equivalent to $116/MWh on a levelized basis.[9] In the Lower Avoided Costs Scenario, I use a lower levelized avoided cost of $60/MWh.

Note that I am not suggesting that either of these is the “correct” estimate of avoided costs at this time. I have chosen these avoided costs to represent a reasonable range of potential avoided costs. In future rate impact analyses, the Company should apply more detailed avoided cost assumptions based upon the most recent information, methodologies and modeling analyses available.

Q. How are annual costs calculated in the With-PV scenarios?

A. The costs in the With-PV Scenarios are equal to the costs in the Without-PV Scenario, minus the avoided costs from the PV.

Q. How is the energy rate calculated in the With-PV Scenarios?

A. The energy rate in the With-PV scenarios is equal to the annual cost of that scenario divided by the annual sales of that scenario. This ratio takes account of both the downward pressure on rates due to avoided costs and the upward pressure on rates due to reduced sales.

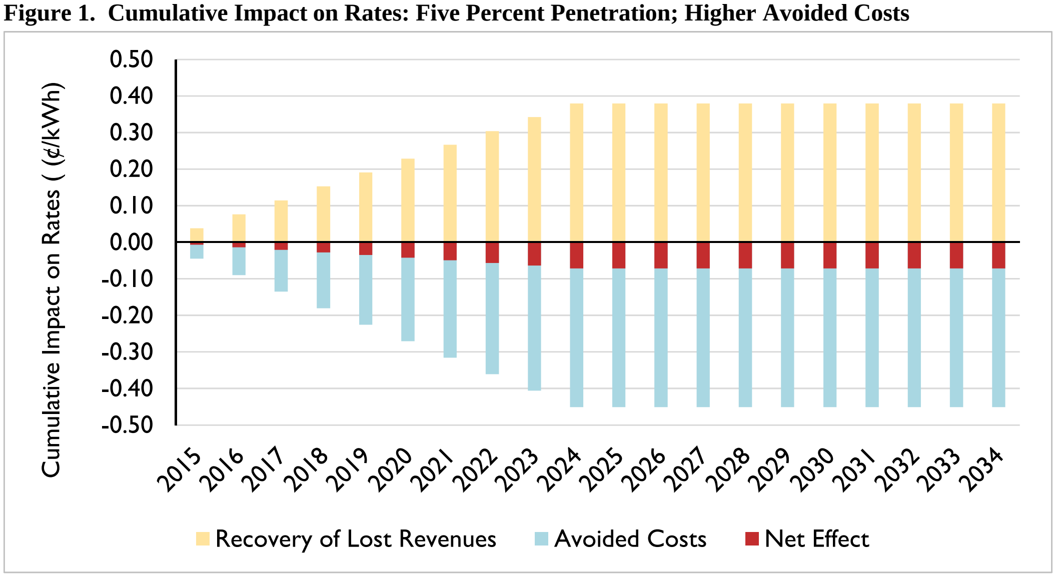
[9] Clean Power Research, *Value of Solar in Utah*, Prepared for Utah Clean Energy, January 7, 2014, p.11.

Results of the Illustrative Rate Impact Analysis

Q. Please summarize your findings from the Five Percent Penetration scenarios.

A. I will begin with the results of the Five Percent Penetration and Higher Avoided Cost Scenario. Figure 1 presents the results of this scenario graphically. It indicates the extent to which recovery of lost revenues will increase rates, the avoided costs will reduce rates, and the net rate impact of the two effects. The analysis indicates that by 2024 these two forces will net out to a minor reduction in rates, equal to roughly 0.07 ¢/kWh, or roughly 0.7 percent of rates.

Figure 1. Cumulative Impact on Rates: Five Percent Penetration; Higher Avoided Costs

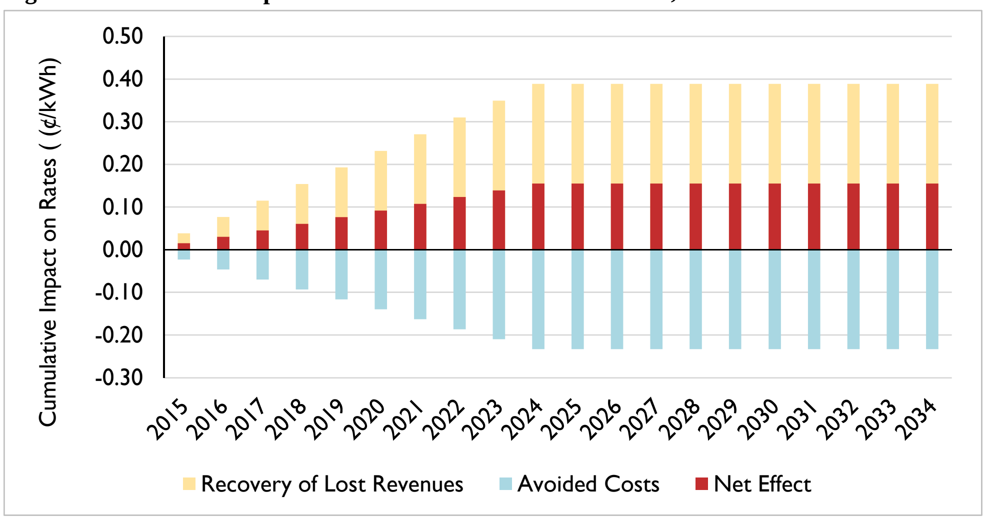


In this scenario the avoided costs are higher than the retail rate, which means that the downward pressure on rates from avoided costs exceeds the upward pressure on rates from the recovery of utility lost revenues. This is what causes the net reduction in rates.

Q. Please summarize your findings from the Five Percent Penetration Scenario with lower avoided costs.

A. Figure 2 presents the results of this scenario graphically. It indicates the extent to which recovery of lost revenues will increase rates, the avoided costs will reduce rates, and the net rate impact of the two effects. The analysis indicates that by 2024 these two forces will net out to a minor increase in rates, equal to roughly 0.16 ¢/kWh, or roughly 1.6 percent of rates.

Figure 2. Cumulative Impact on Rates: Five Percent Penetration; Lower Avoided Costs

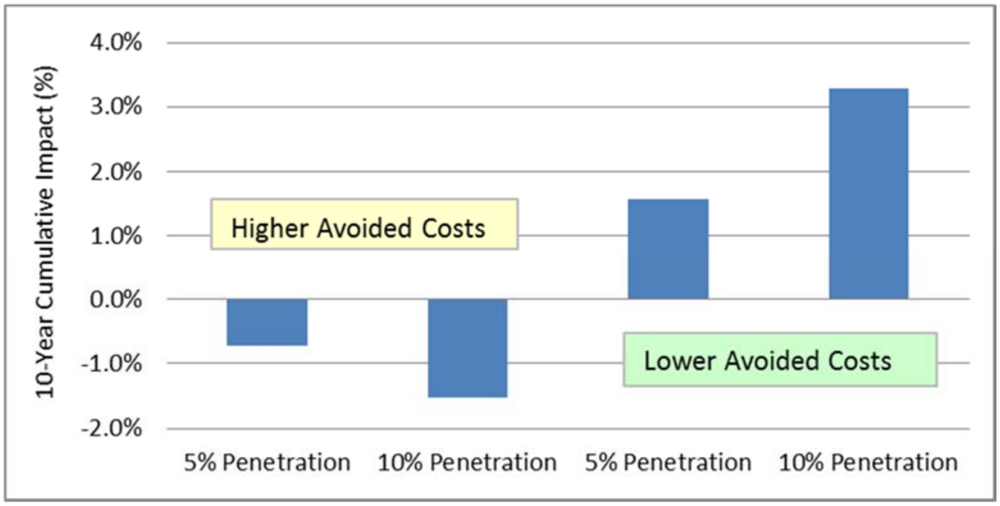


In this scenario the levelized avoided costs are lower than the residential retail rate. Consequently, the downward pressure on rates is smaller than the upward pressure on rates, resulting in a net rate increase.

Q. Please summarize your findings from the Ten Percent Penetration Scenario.

A. The findings of the Ten Percent Penetration Scenario are similar to the findings above, except that the magnitudes are greater. Figure 3 presents the cumulative rate impacts by 2024 of the four scenarios: five percent and ten percent penetration with higher and lower avoided costs. As indicated, with greater penetration of PV the potential reduction or increase in rates will be commensurately greater. The rate impact under the Ten Percent Penetration Scenarios could be as small as a 1.5 percent reduction in rates or as high as a 3.3 percent increase in rates.

Figure 3. Ten-Year Cumulative Impact on Rates by 2024; Four Scenarios



Q. Please summarize your findings in terms of year-to-year rate impacts?

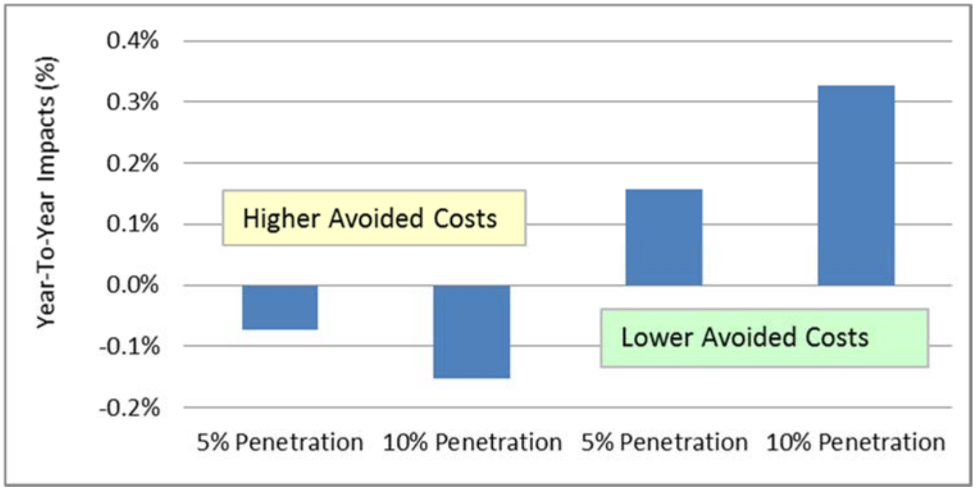
A. As noted above, the rate impacts presented in Figures 1, 2 and 3 compare two hypothetical scenarios: one without new PV and one with new PV. Customers will not actually observe these rate impacts because only one future scenario will take place.

The year-to-year rate impacts use the same information from above, but focus only on the change in rates from one year to the next in the With-PV scenarios. Figure 4 presents a summary of the year-to-year rate impacts under the different scenarios analyzed.

- For the Higher Avoided Cost Scenarios the year-to-year rate impacts are estimated to be reductions in rates in the range of slightly less than 0.1 percent to slightly more than 0.1 percent per year for the years 2016-2024, and then zero after that.

- For the Lower Avoided Cost Scenarios the year-to-year impacts are estimated to be an increase in rates of roughly 0.1 to 0.3 percent per year for the years 2016-2024, and then zero after that.

Figure 4. Year-To-Year Rate Impacts; Four Scenarios



It should be noted that these year-to-year rate impacts are quite small, given the uncertainties and the very general assumptions used in my analysis. These rate impacts could be described as being so small as to be "in the noise" of the analysis.

Q. What conclusions do you draw from your rate impact findings?

A. These findings suggest that the rate impacts from NEM are likely to be quite small, and possibly even negative. In particular, the year-to-year rate impacts will be very small.

Q. Why do you think the rate impacts of NEM are so small?

A. The rate impacts of NEM are likely to be very small because the cost of the PV systems are paid for by the host customers. The PV generation is essentially a free resource to the utility system, and it is provided at a time when power costs are typically at their highest.

This eliminates one of the biggest factors that leads to increased rates: the cost of the resource itself.

6. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. Two different set of metrics should be used to assess the costs and benefits of NEM in Utah: a cost impact and a rate impact.

The cost impact analysis should use the same analytical framework, i.e., the same costs and benefits, as the Utility Cost Test used to evaluate DSM resources.

The rate impact analysis should use the assumptions that are used in the cost impact analysis, but should also estimate the long-term rate impacts in terms of terms of ¢/kWh, percent change in rates, or dollars per customer per month.

The rate impacts of NEM are likely to be very small, because the cost of the PV system is borne by the host customer.

The RIM Test should not be used to evaluate the costs and benefits of NEM because it suffers from several fundamental flaws and presents results that are misleading.

Q. Please summarize your primary recommendations.

A. I recommend the following:

- The Commission should approve an analytical framework consisting of two sets of metrics to indicate the costs and benefits of NEM in Utah: one set of metrics for cost impacts, and a separate set of metrics for rate impacts.

- The Commission should require that the cost impact analysis be based on the costs and benefits included in the Utility Cost Test.
- The Commission should require that the rate impact analysis estimate the long-term percent change in customer rates resulting from NEM. The rate impact analysis should also indicate the year-to-year rate impacts of NEM.
- The Commission should require the Company to prepare the cost impact analysis and the rate impact analysis, using the best available methodologies, inputs and assumptions.
- The Commission should find that the Rate Impact Measure Test shall not be used to analyze the costs and benefits of NEM.

Q. Does this conclude your direct testimony?

A. Yes, it does.