Nevada Net Energy Metering Impacts Evaluation

Prepared for:
State of Nevada Public Utilities Commission

July 2014

Energy+Environmental Economics

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1 Executive Summary

1.1 Net Metering Program Overview

This study was commissioned by the Public Utilities Commission of Nevada (PUCN) in response to Nevada Assembly Bill (AB) 428[1] to forecast the costs and benefits of renewable generation systems that qualify for the state's net energy metering (NEM) program. Energy + Environmental Economics (E3), hereafter referred to as "we", completed the study under direction of the PUCN and with input from a stakeholder advisory group composed of experts from the solar industry, ratepayer advocates, and electric utility representatives. This work was completed under PUCN Docket No. 13-07010.[2]

NEM is an electricity tariff designed to encourage installation of customer-sited renewable generation. Under the NEM tariff, a customer can self-generate electricity, reducing purchases from the utility, and sell excess electricity back to the utility at retail rates. Customers with solar photovoltaic (PV), solar thermal electric, wind, biomass, geothermal electric, or hydroelectric distributed generation (DG) installations are eligible for Nevada's NEM tariff.

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[1] Assembly Bill No. 428 – Committee on Commerce and Labor, available at: http://www.leg.state.nv.us/Session/77th2013/Bills/AB/AB428_EN.pdf

[2] Docket can be found at: http://pucweb1.state.nv.us/PUC2/DktDetail.aspx

A number of complimentary programs in Nevada also serve to encourage DG installations in the state. Some DG systems receive financial incentives through NV Energy's RenewableGenerations program. Generation from these incentivized systems can be counted towards Nevada's renewable portfolio standard (RPS), which requires NV Energy (Nevada's two electric utilities, Nevada Power Company and Sierra Pacific Power Company, jointly) to produce 25% of its generation from eligible renewable resources by 2025. Lastly, the Federal Investment Tax Credit (ITC) works to incentivize DG installations by offsetting 30% of eligible installed system capital costs through the end of 2016 (when it drops to 10%).

As of December 2013, over 3,300 individual systems were enrolled in NV Energy's NEM program, totaling over 60 Megawatts (MW) of installed capacity, with 50 MW coming from distributed PV. These systems produce about 93 Gigawatt-hours (GWh) of energy annually. Forecasts of new installations from 2014 to 2016 provided by NV Energy anticipate significant growth (234 MW) in new NEM capacity through 2016.

1.2 Scope of Analysis and Results

In this study, we investigate the future (2014 onward) impact of existing NEM systems and forecasted installations through 2016. We evaluate Nevada's NEM program through three analyses: a cost-benefit analysis, a review of NEM's macroeconomic impacts, and a demographic comparison of NEM participants and non-participants in the state.

1.2.1 COSTS AND BENEFITS OF NEM

We evaluate the cost-effectiveness of NEM generation from five different perspectives to provide a comprehensive assessment of the costs and benefits of the NEM program. These tests are typically applied when assessing the cost-effectiveness of distributed resources and reflect the industry standard used in all 50 states.[3] The core questions the cost-effectiveness assessment answer are the following:

1) Is renewable self-generation cost-effective for the customers who install systems? (Participant Cost Test or "PCT")
2) What is the cost impact on non-participating utility customers? (Ratepayer Impact Measure or "RIM")
3) Recognizing that some utility bills may go down and others may go up, does the NEM program reduce utility bills overall? (Program Administrator Cost Test or "PACT")
4) Does NEM generation reduce the overall cost of energy for Nevada? (Total Resource Cost Test or "TRC")
5) Does NEM generation provide net societal benefits considering the cost and externalities such as the health impacts from NEM? (Societal Cost Test or "SCT")

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[3] The 'cost tests' are defined in the California Standard Practice Manual used nationwide which is available for download at: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf**.** The cost tests described in the manual are used throughout the United States.

The overall policy and incentive structure used in Nevada to encourage renewable self-generation has recently changed, and is anticipated to change further through 2016. Therefore, we report cost-effectiveness results separately for systems installed through 2013, systems installed in 2014 and 2015, and 2016-vintage systems. The forecasted cost-effectiveness of systems in 2016 incorporates all of the programmatic changes currently planned for NEM-eligible systems and reflects the likely impact before any additional policy changes. The most important policy changes over the analysis timeframe that are incorporated into this report are the following:

- In 2014, the RenewableGenerations incentive program is being redesigned with significantly lower incentive levels and open, on-going availability. This new design replaces the prior lottery-based system, under which utility incentives were only available to those that won the lottery. The new design also includes more stringent performance requirements for wind systems and replaces the old capacity-based incentive with a performance-based incentive (PBI) for wind and large PV systems.
- Effective starting in 2014, NV Energy has adjusted the NEM tariff such that compensation for exports to the grid no longer include a payment for public purpose charges. This reduces the compensation for NEM systems somewhat. NEM generation that displaces on-site load still benefits from reduced public purpose charges.

- In 2016, the credits towards the Nevada RPS for solar generation will no longer be counted with a multiplier on production. All eligible generation will be counted towards the RPS on an equal basis. Prior to 2016, utility-sited solar generation is awarded a 2.4 multiplier towards RPS compliance, and distributed solar generation is awarded a 2.45 multiplier.

We collaborated with the PUCN with input from the stakeholder advisory group to define a "base case" set of input assumptions. The data used in the study is primarily sourced from NV Energy's most recent integrated resource plans, general rate cases, and RenewableGenerations incentive program reports. We also analyze some sensitivity cases in which we alter various key assumptions. In both the base and reference cases, all other state policies (in particular, Nevada's RPS) remain intact.[4]

1.2.2 BASE CASE RESULTS

In the Base Case we find the following results for each of the five perspectives of cost-effectiveness.

1. **Is renewable self-generation cost-effective for the customers who install systems? (Participant Cost Test or "PCT")**

Prior to 2014, the RenewableGenerations incentive levels were relatively high, and renewable self-generation was cost-effective for the average Nevada NEM

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[4] This study does not incorporate any effects of Senate Bill (SB) 123. The impacts of excluding SB 123 are addressed in Section 2.3.4.

customer. In 2014, with the reduction in utility incentives, self-generation looks moderately more expensive than conventional utility service for the average Nevadan unless installed renewable generation costs drop faster than we forecast. This result is driven by lower state incentives, and also new incentive program performance requirements for wind, and removal of the public purpose charge credit for exports. Of course, competition and industry cost improvements of renewable self-generation suppliers may reduce prices faster than our forecast. As shown in Table 1, on average, the NEM participants at the end of 2016 are expected to pay on a lifecycle basis about $0.02/Kilowatt-hour (kWh) more for energy they self-generate than if they would have purchased from the utility, which adds up to a net present value (NPV) of -$135 million dollars over the 25-year lifetime of the systems.

Table 1: Base Case Results of NEM Generator Participant Cost-Effectiveness; Participant Cost Test (PCT)

Benefit (cost) to customers who participate in NEM	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($MM 2014)	$23	($115)	($43)	($135)
Levelized ($2014/kWh)	$0.02	($0.03)	($0.04)	($0.02)

2. Does renewable self-generation impact the other NV Energy ratepayers? (Ratepayer Impact Measure or "RIM")

Prior to 2014, there was a significant cost shift from NEM customers to non-participating customers, primarily because the funding of the RenewableGenerations incentive was relatively large and impacted the bills of all customers.

In 2014 and 2015, we anticipate a benefit to non-participants because a) the utility incentive is relatively low, and b) the RPS policy places a large value on distributed solar generation installed during this time period. The 2.45 multiplier on RPS credits from solar self-generation installed prior to 2016, combined with unlimited banking of RPS credits and current RPS over procurement means that the utility will avoid purchasing 2.45 kWh of central station renewables on behalf of all customers for every kWh of NEM generation from 2004 through 2015 vintage NEM systems.

In 2016, the RPS multiplier will have expired and the RenewableGenerations incentives will be low, so we expect that non-participants are very nearly neutral and will experience neither a large benefit nor a cost due to new NEM installations.

Overall, we do not estimate a substantial cost shift to non-participants due to NEM going forward given the current and proposed reforms to the program. We estimate a total NPV benefit of 2004-2016 NEM systems to non-participating ratepayers of $36 million during the systems' lifetimes. Whether NEM systems are a net cost or net benefit to non-participants is sensitive to some key input assumptions, as demonstrated by the sensitivity results (Section 1.2.3), but in either case should be relatively small.

Table 2 presents the expected impacts to non-participants for each vintage of NEM generation. Overall, the planned reforms significantly reduce costs to non-participants while reducing the financial proposition to those that would install self-generation.

Table 2: Base Case Results of NEM Generator Non-Participating Ratepayer Cost-Effectiveness; Ratepayer Impact Measure (RIM)

Benefit (cost) to non-participating ratepayers	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($MM 2014)	($141)	$168	$6	$36
Levelized ($2014/kWh)	($0.14)	$0.05	$0.01	$0.01

3. **Overall, do the bills NV Energy collects from all customers (both participants and non-participants) increase or decrease due to NEM systems? (Program Administrator Cost Test or "PACT")**

Prior to 2014, NEM caused bills to increase slightly overall because utility incentives exceeded the utility costs avoided by the NEM generation. For future vintages, when incentives are lower, the total bills NV Energy collects will decrease substantially due to the self-generation. In total, we estimate that bills will decrease by NPV $716 million for all systems installed through 2016 over their 25-year life. Of course, as discussed previously, all of the bill savings accrue to those who install self-generation and these savings do not include the costs of the systems themselves since this perspective is only focused on the change in utility bills.

Table 3 presents the results on the aggregate change in total bills attributable to each vintage of system and the levelized bill savings from each kWh of NEM generation. The results show a benefit (cost) to customers as a whole thanks to an aggregate reduction (increase) in their electric bills. From a utility-perspective, this result shows that the utility will need to collect less (more) revenue from customers (typically called the ‘revenue requirement’) overall as more customers generate their own electricity to earn their target rate of return. The levelized bill savings per kWh are driven significantly by the value of the renewable energy credit from incentivized systems that can be used to displace central station renewables. In particular, the savings are significant on systems installed prior to 2016 that receive a 2.45 multiplier.

Table 3: Base Case Results of NEM Generator Program Administrator (Utility) Cost-Effectiveness; Program Administrator Cost Test (PACT)

Reduction (increase) in aggregate customer bills	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($MM 2014)	($28)	$581	$160	$716
Levelized ($2014/kWh)	($0.03)	$0.17	$0.13	$0.13

4. Is self-generation a cost-effective resource for Nevada? (Total Resource Cost Test or "TRC")

Overall, NEM generation moderately increases total energy costs, primarily because large-scale, utility-sited renewable generation is a lower cost resource. Since RenewableGenerations-incentivized systems count towards the Nevada 25% RPS, they displace the need for NV Energy to purchase additional wholesale renewable generation in approximately the 2020 timeframe when the banked renewable credits would be exercised. Therefore, this result is driven by the cost difference between smaller self-generation systems when installed and the cost of central station renewable generation in 2020 compared to the additional benefits of distributed NEM generation.

Table 4, below, summarizes the results of the overall costs to Nevada for each vintage of NEM installation. Prior to 2014, the relatively higher cost of NEM generation systems is the primary driver of a net cost to Nevada for early systems. For the systems installed from 2014-2015, the forecasted cost declines of NEM systems coupled with the multiplier that displaces 2.45 kWh of central station in 2020 for every kWh generated by a NEM system reduces costs for Nevada. When the RPS multiplier is removed for 2016 NEM vintages, we find that NEM will again be a net cost to the state. Our forecasts predict that the cost advantage of utility-scale renewable systems outweighs the additional loss and transmission benefits of small distributed NEM systems.

Table 4: Base Case Results of NEM Generator Total Resource (State) Cost-Effectiveness; Total Resource Cost (TRC) Test

Benefit (cost) to the state of Nevada	Installs through 2013 Lifecycle NPV $MM	Installs in 2014-2015 Lifecycle NPV $MM	Installs in 2016 Lifeycle NPV $MM	All installs through 2016 Lifecycle NPV $MM
Lifecycle NPV ($MM 2014)	($119)	$52	($36)	($100)
Levelized ($2014/kWh)	($0.12)	$0.02	($0.03)	($0.02)

5. How does this conclusion change if we consider non-monetized benefits of renewables? (Societal Cost Test or "SCT")

Inclusion of a societal perspective, which includes externalities and non-monetized health benefits of reduced air emissions from self-generation, does not significantly change the results of our findings for the costs and benefits of NEM for Nevada overall. The primary reason is that Nevada has a 25% RPS, and if less NEM is installed then more utility-sited renewable generation will be installed (and vice-versa) to meet the standard. Therefore, there is no substantial net emissions reduction or additional health benefits attributable to NEM systems.

In fact, given the 2.45 multiplier on NEM systems installed now we find that NEM systems *increase* emission levels and produce a net health cost in the long-run. Because customers install NEM systems when it is in their own interest, NEM capacity is installed before NV Energy would otherwise need to build utility-scale renewables for RPS compliance. This results in a net emissions reduction in the early years of the analysis. However, renewable generation from NEM PV systems installed prior to 2016 receives the 2.45 RPS multiplier and reduces the total installed renewable generation by 2025. In addition, installing NEM generation reduces the RPS requirement because the 25% RPS is linked to the total retail sales which are reduced by NEM. Consequently, generating 1 kWh of NEM generation prior to 2016 will displace about 2.7 kWh (2.45 multiplier plus 0.25 RPS requirement) of future utility-sited renewable generation. This will result in less renewable generation and more emissions overall.

Table 5, below, summarizes the results from a societal perspective for each vintage of installed NEM generation. The main driver of differences in the NPVs of Table 4 and Table 5 is the difference in rates used to discount the cost streams. As is standard utility practice, we use a lower societal discount rate (we assume 3% real) for the societal perspective and the utility cost of borrowing (we assume 4.7% real) for the TRC. It is conventional for societal cost-effectiveness analyses to put more emphasis on future time periods and future generations.

Table 5: Base Case Results of NEM Societal (State) Cost-Effectiveness; Societal Cost Test (SCT)

Benefit (cost) to the state of Nevada, including externalities	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($MM 2014)	($133)	$90	($36)	($75)
Levelized ($2014/kWh)	($0.11)	$0.02	($0.02)	($0.01)

1.2.3 SENSITIVITY RESULTS

In addition to the base case, we evaluate NEM cost-effectiveness under five alternative assumptions on key drivers to investigate their impact on the analysis results. Of these five sensitivities, two impact the utility value of NEM generation and three impact NEM customer bill savings. We also outline additional sensitivities that can be performed using the publicly available spreadsheet models.

1.2.3.1 Sensitivity 1: Distribution Avoided Costs

In the first sensitivity, we consider the cost-effectiveness of NEM assuming that NEM generation would allow the utility to avoid building distribution upgrades to serve customer loads. This benefit is not included in the base case because NV Energy distribution engineers do not consider the intermittent output of NEM systems reliable enough to avoid the need for distribution system upgrades. In reality, some portion of distributed generation could probably reliably defer some distribution upgrades, though distribution planning processes would need to be modified to actually capture the distribution value. Therefore, including the distribution component of avoided costs provides a high estimate of net metered systems' benefit to the grid. Table 6 shows the results of each affected cost test is shown with the inclusion of distribution benefits. Including distribution benefits increases net benefits under each of the other cost tests. There are greater benefits to non-participants if the utility could capture distribution benefits, the overall bill savings would be larger in Nevada. Finally, based on our assessment, NEM generation could become a net benefit to the state of Nevada with the inclusion of distribution benefits.

Table 6: Results with Distribution Avoided Costs

	Primary Question What is the…	Installs through 2013 Lifecycle NPV $MM	Installs in 2014-2015 Lifecycle NPV $MM	Installs in 2016 Lifeycle NPV $MM	All installs through 2016 Lifecycle NPV $MM
RIM	benefit (cost) to non-participating ratepayers?	($118)	$246	$35	$166
PACT	reduction (increase) in aggregate customer bills?	($4)	$659	$189	$847
TRC	benefit (cost) to the state of Nevada?	($95)	$131	($8)	$31
SCT	benefit (cost) to the state of Nevada, including externalities?	($105)	$184	($1)	$82

1.2.3.2 Sensitivity 2: Retail Rate Design

Retail rates also play an important role in NEM cost-effectiveness. We performed a second sensitivity analysis comparing several different potential rate designs. NV Energy created these hypothetical rates for our analysis: each rate scenario represents shifting an additional component of the utility revenue requirement from the rates' variable charges ($/kWh) to fixed monthly charges ($/month). The "Rule 9 Compliance" rate design collects more revenue in fixed charges than the current design, and the "Rule 9 Compliance + Primary Distribution Cost Recovery" rate design collects an even larger portion of revenue in fixed charges. Table 7 below shows the results of the RIM and PCT after each potential rate design change. These results are displayed for all NEM installations through 2016. As each successive rate change moves more charges from the variable portion of the rate to the fixed portion, NEM participant benefits decrease and non-participating ratepayer benefits increase. This is because NEM participants are compensated for energy exports at the level of the variable rate; lower variable rates reduce the cost shift from participants to non-participants.

Table 7: Sensitivity Results of Non-Participant Impacts for Alternative Rate Designs, All NEM Installations Through 2016

	PCT What is the benefit (cost) to customers who participate in NEM?	RIM What is the benefit (cost) to non-participating ratepayers?
	Lifecycle NPV ($MM)	Lifecycle NPV ($MM)
Base Case: Existing Rate Structures	($135)	$36
Sensitivity: Rule 9 Compliance	($148)	$48
Sensitivity: Rule 9 Compliance + Primary Distribution Cost Recovery	($195)	$95

1.2.3.3 Sensitivity 3: Retail Rate Escalation

We also performed a sensitivity analysis on NV Energy's retail rate escalation through the end of the study period (2041). NV Energy's integrated resource plan

(IRP) provides a base retail rate escalation, but it is extended only through 2020. In our base case, we use NV Energy's IRP gas forecast to extend the retail rate escalation from 2020 to 2041, resulting in a real annual rate increase of 1.4% beyond 2020. In Table 8, we compare two additional retail rate escalations, one higher and one lower than the base assumption. Effectively, the retail rate is the price that the utility is purchasing NEM generation on behalf of customers so the higher the retail rate the more costly NEM generation is for non-participants, and the better the proposition is for NEM generation owners. We find that the higher retail rate escalation would create a moderate cost burden on non-participants (rather than a moderate benefit). The lower retail rate escalation results in the reverse outcome, less economic benefits to participants, and greater net benefits to non-participants.

Table 8: Sensitivity Results of Retail Rate Escalation, All NEM Installations Through 2016

	PCT What is the benefit (cost) to customers who participate in NEM?	RIM What is the benefit (cost) to non-participating ratepayers?
	Lifecycle NPV ($MM)	Lifecycle NPV ($MM)
Base Case: IRP forecast extended beyond 2020 at 1.4% real	($135)	$36
High rate escalation: 1.4% real in all years	($98)	($2)
Low rate escalation: IRP forecast extended beyond 2020 at 0.5% real	($168)	$68

1.2.3.4 Sensitivity 4: Demand Charge Reduction

The base case analysis assumes that intermittency of NEM generation and poor coincidence of generation and customer load prevents customers from reducing their monthly peak demand. We therefore assume no demand charge savings on customer bills due to NEM in the base case. We performed a sensitivity in which NEM customers on rates that include demand charges could reduce demand in all of the relevant hours by 10%. We believe that this is a high estimate, so we use this to set an upper bound on the potential impact of demand charge reduction.

As shown in Table 9, NEM demand charge reductions shift about $17 million NPV from NEM participants to non-participating ratepayers. The inclusion of a demand charge has no impact on the other three cost tests.

Table 9: Sensitivity Results of Demand Charge Reduction, All NEM Installations Through 2016

	PCT What is the benefit (cost) to customers who participate in NEM?	RIM What is the benefit (cost) to non-participating ratepayers?
	Lifecycle NPV ($MM)	Lifecycle NPV ($MM)
Base Case: No Demand Charge Reduction	($135)	$36
Sensitivity: 10% Demand Charge Reduction	($119)	$19

1.2.3.5 Sensitivity 5: Large-Scale, Utility-Sited PV PPA Price

Because this analysis is partly driven by a comparison of the cost-effectiveness of NEM displacing utility-sited solar assets, the assumed cost of utility-sited renewables is a key driver of results. In the base case, we estimate the cost of utility-sited renewables as $100/Megawatt-hour (MWh) ($2014) for systems installed in 2020 based on a forecast using publicly-available data on solar power purchase agreements (PPAs). This price assumes that the federal investment tax credit steps down to 10% in 2017. Because there is usually a delay in the public availability of actual utility cost data, and this is a long run forecast, the actual price of utility-sited renewables is uncertain. Therefore, we performed two utility-scale solar PPA price sensitivities: one low estimate of $80/MWh; and one high estimate of $120/MWh.

Table 10 shows the results of each of the four cost tests influenced by utility-scale solar PV PPA price. The cost of utility-sited renewables does not impact the benefits to NEM participants. A significant conclusion from the results is that the solar PPA price can drive the sign of many of the cost-effectiveness results. With a low utility-scale solar PPA price of $80/MWh, the costs of NEM generation are relatively higher in comparison which makes all of the affected cost tests of NEM generation worse. With a higher utility-scale solar PPA price of $120/MWh, the opposite is true, and NEM generation is relatively better choice. We find that this range of utility-scale solar PPA price uncertainty changes the answer on the overall economic proposition of NEM generation for Nevada.

The impact of the solar PPA price is largest for existing and 2014-2015 vintage systems due to the RPS multiplier. Still, the base case cost-effectiveness of non-participating ratepayers and the state of Nevada are close enough to zero that the solar PPA price influences the sign of these cost tests.

Table 10: PPA Price Sensitivity Cost-Effectiveness Results (lifecycle NPV $MM 2014)

		Lifecycle NPV ($MM)			
	PPA Price ($/MWh)	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
RIM	$80	($189)	($13)	($24)	($222)
	$120	($94)	$349	$37	$295
PACT	$80	($75)	$400	$130	$458
	$120	$20	$762	$191	$976
TRC	$80	($166)	($128)	($66)	($358)
	$120	($71)	$233	($6)	$160
SCT	$80	($190)	($136)	($75)	($397)
	$120	($75)	$316	$3	$248

1.2.3.6 Other Sensitivities

In addition to the sensitivities included in this report, a number of other key input assumptions have a significant impact on the results of this analysis. We have created three publicly-available spreadsheet tools to allow stakeholders to modify these other assumptions and view the cost test results of the additional sensitivities they create. The public models also provide transparency into the inputs, calculations, and methodology used in this analysis. The models can be downloaded from the PUCN website.[5]

The assumptions that can be modified in the public models include:

- the forecast of utility rates through analysis horizon (2014 to 2041)
- the forecast of energy costs through the analysis horizon
- the number of systems installed from 2014 through 2016
- the installed costs of NEM generators
- the useful lifetime of NEM installations
- discount rates

1.2.4 MACROECONOMIC IMPACTS

The impact of NEM and other renewable energy on jobs and the economy of Nevada is an important issue for policy makers as they consider policies that promote electricity generation from renewable resources. Accurately estimating all of the macroeconomic impacts of NEM would require complex, expensive models that lack transparency. We conduct a literature review and leverage existing studies on the macroeconomic impacts of renewable and greenhouse

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[5] http://puc.nv.gov/Utilities/Electric/

gas (GHG) policies to make inferences about the lifetime macroeconomic impacts of NEM systems installed in Nevada through 2016.

The macroeconomic impacts of NEM installed through 2016 in Nevada could potentially be positive or negative. Comparable macroeconomic studies of renewable policies find net negative macroeconomic impacts. These studies indicate that the solar industry does indeed create jobs, but the negative impact of average electricity retail rate increases tends to outweigh the positive impacts. However, because we find that NEM will most likely not increase rates in Nevada, it is plausible that NEM will have a positive macroeconomic impact in Nevada.

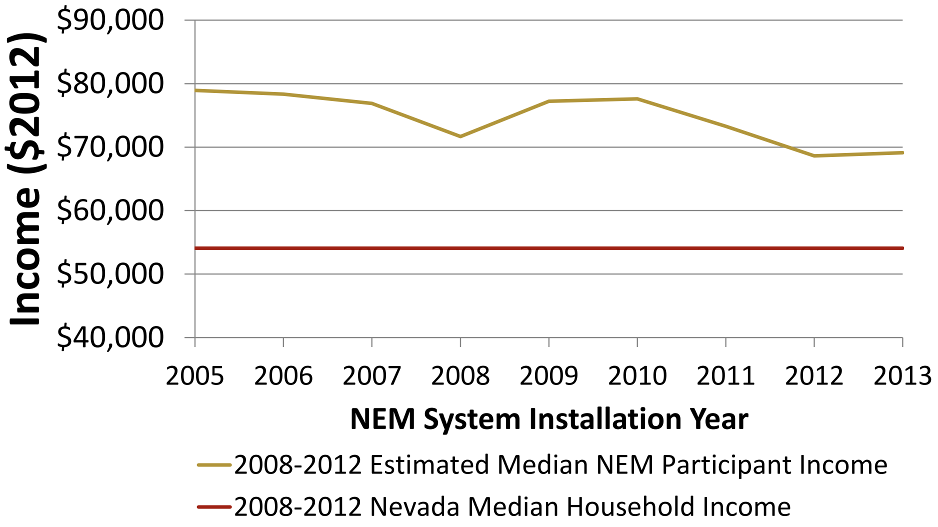
Whether the impact is positive or negative, we find that the net macroeconomic impacts will be very small relative to the size of the Nevada economy. The macroeconomic impacts in the studies reviewed were themselves small, and the scopes of most of the studies reviewed were degrees of magnitude greater than the installed NEM capacity forecasted in Nevada through 2016.

1.2.5 DEMOGRAPHIC ANALYSIS

Another important consideration is the demographic makeup of the NEM participant population relative to the demographics of the state. We compare the median income of NEM participants to the state's median income from 2005 to 2013. We assume that the income of each NEM participant was equal to the median income of the participant's census block group (identified using customer addresses). Census block group is the most detailed assessment available of household incomes, with each census group constructed to encompass approximately 4,000 households with similar demographics.

The resulting 2013 median income of NEM participants is $67,418, while the Nevada median income is $54,083. Therefore, the customers who install NEM generation typically have higher incomes than Nevadans overall. Figure 1 displays the temporal trends in 2008-2012 NEM participant census block group median income by installation year against the 2008-2012 Nevada median income.

Figure 1: NEM Participant and Nevada Median Incomes



1.2.6 SUMMARY OF KEY FINDINGS

The following points summarize the key findings of this analysis:

- Nevada has implemented or has planned a number of reforms that affect the NEM generation cost-effectiveness through 2016. In particular, many of these reforms rebalance the costs and benefits between customers who install NEM generation and non-participating customers. By 2016, assuming all of the reforms occur, non-participants will be approximately indifferent to customers that do install NEM generation. A key element of this finding is that the utility is allowed to offset utility-scale renewable purchases for NEM generation.

- While high utility incentives have historically encouraged customers to install NEM systems, with lower incentive levels implemented in 2014, we expect the market for renewable self-generation will need to provide lower prices to customers for Nevada to attain high levels of future NEM adoption.

- Overall, for the state of Nevada, we find that NEM generation is a moderately more costly approach for encouraging renewable generation than utility-scale renewables. However, the difference is small enough that uncertainty in future costs of utility-scale renewable generation changes this answer. We find that NEM generation participants will bear these additional costs rather than non-participating customers.

- The macroeconomic impacts of NEM installed through 2016 in Nevada are likely positive, but will be very small relative to the size of the Nevada economy.

- The customers who install NEM generation typically have higher incomes than the median income in Nevada.

2 Introduction

2.1 Analysis Overview

This study was commissioned by the PUCN in response to Nevada AB 428 to forecast the costs and benefits of renewable generation systems that qualify for the state's NEM program. We completed the study under direction of the PUCN and with input from a stakeholder advisory group composed of experts from the solar industry, ratepayer advocates, and electric utility representatives. This work was completed under PUCN Docket No. 13-07010.

NEM is an electricity tariff designed to encourage installation of customer-sited renewable generation. Under the NEM tariff, a customer can self-generate electricity, reducing purchases from the utility, and sell excess electricity back to the utility at retail rates.

This study evaluates the comprehensive costs and benefits of generation systems eligible for NEM in Nevada. As required by the legislation, this study analyzes the impacts of NEM generation on each of the following parties:

- customer-generators who participate in NEM;
- utility customers who do not participate in NEM;
- all utility customers overall;
- the State of Nevada; and

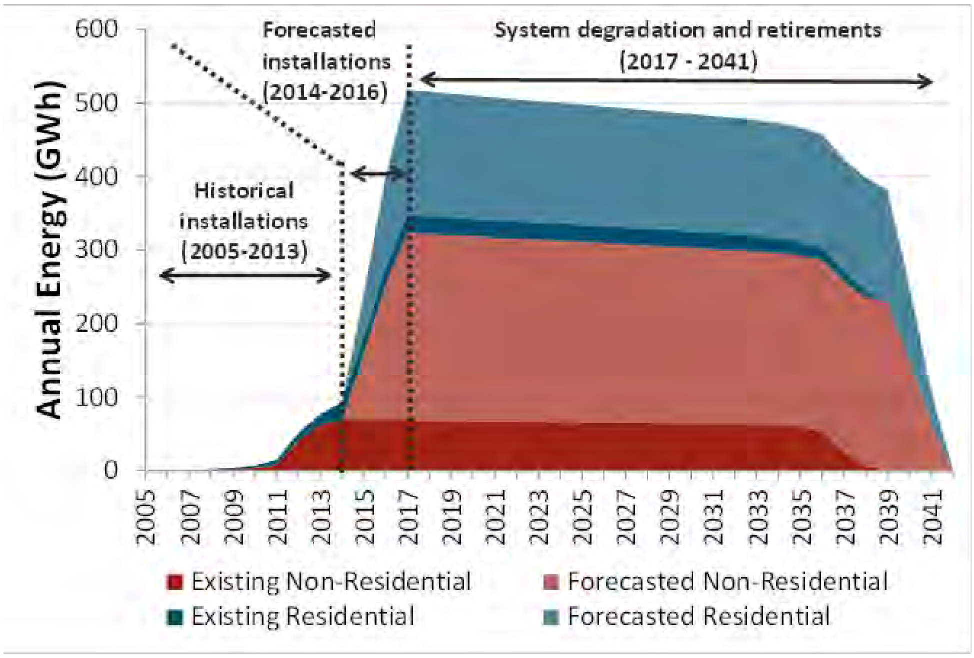
- the State of Nevada including non-monetized health benefits.

In addition to cost-effectiveness analysis, we investigate the likely macroeconomic of impact of NEM generation to assess the impact, if any, on jobs and economy in the state. Since accurately estimating the macroeconomic impacts of NEM would require complex, expensive models that lack transparency, we conduct a literature review and leverage existing studies on the macroeconomic impacts of renewable and GHG policies to make inferences about the lifetime macroeconomic impacts of NEM systems installed in Nevada.

Finally, we analyze the median household income of those customers who take advantage of the NEM program and compare to the median income in Nevada overall. This analysis is provides more context on the participating and non-participating customers.

This analysis considers net metering systems installed through 2016, including all existing NEM systems as well as forecasted installations from 2014 through 2016. The size of the NEM program through 2016 is forecasted to be fairly small relative to the size of NV Energy. In 2016, NV Energy forecasts NEM generation to be about 1% all NV Energy generation. NEM installed capacity is expected to be about 3% of peak demand, and about 1.2% of NV energy customers are expected to install NEM systems. Figure 2 shows annual historical and forecasted NEM generation of systems installed through 2016 over their lifetimes.

Figure 2: Annual Energy Generation of NEM Systems



2.2 NEM Program

2.2.1 NEM RATE STRUCTURE FOR CUSTOMER-GENERATORS

In Nevada, customers with qualifying distributed renewable energy systems can participate in the NEM program. Under NEM tariffs, customer-generators are billed based on their monthly net electricity consumption. For each month in which a NEM customer's usage exceeds the customer's generation, the kWh generation credits are applied directly against the customer's usage to reduce the month's electricity bill. Any excess kWh credits remaining in a billing month are carried forward indefinitely, and they may be used only to offset future electricity charges.

Under this system, only the variable cost portion of the bill ($/kWh usage) and demand charge portion ($/Kilowatt (kW) of peak demand during the billing period) can be avoided. Any portion of the bill based on fixed charges ($/month) cannot be avoided by NEM. In addition, starting in 2014, NEM customers cannot avoid public purpose charges for NEM generation in excess of usage. Public purpose charges are additional $/kWh charges applied to customers' bills. Funds collected through these charges are used to facilitate alternative and renewable energy projects, incentivize higher energy efficiency, and provide energy assistance to those in need.[6] These charges generally account for less than 5% of a customer's total bill.

Customers with solar PV, solar water heating, wind, biomass, geothermal electric, or hydroelectric DG may participate in the NEM program. In order to qualify for the program, the nameplate capacity of a customer's distributed renewable energy system must not exceed 1 MW, the customer's annual electricity demand, or the demand limit of the customer's customer class.

Nevada legislation enacted the NEM program in 1997. Nevada Power Company (NVE South) and Sierra Pacific Power Company (NVE North), the two Nevada

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[6] NV Energy's public purpose charges are comprised of the following bill components: Temporary Green Power Financing (TRED), Renewable Energy Program (REPR), Energy Efficiency Charge (EE), and Universal Energy Charge (UEC).

investor-owned utilities (IOUs) and subsidiaries of NV Energy holding company, are required to offer NEM until the aggregate capacity of all NEM generators in Nevada totals 3% of peak capacity.[7]

2.2.2 RENEWABLEGENERATIONS PROGRAM

In adherence with AB 431,[8] NV Energy began offering rebates to customers installing NEM-eligible solar PV generators in 2004. The RenewableGenerations program was later expanded to include wind and small hydroelectric systems. Incentive amounts vary by technology and customer sector and are required by law to decline along with installed costs. Incentive levels began at $5 per Watt-Alternating Current (W-AC) for PV and $2.50/W-AC for wind. After a major incentive design change in 2014, proposed incentive levels are now below $1/W-AC for both technologies. See Figure 17 for annual solar and wind incentive levels from 2004 forecasted through 2016.

NV Energy recently filed for approval to transition the RenewableGenerations program towards offering a mixture of upfront rebates and performance-based incentives (PBIs). Under the current proposal, all solar systems greater than 25 kW and all wind and hydroelectric systems would be eligible for PBIs only. PBIs apply to the first five years of production, and the proposed 2014 incentive levels range from $43/MWh to $86/MWh.

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[7] NEM cap definition: http://www.leg.state.nv.us/NRS/NRS-704.html#NRS704Sec766

[8] AB 431 information: http://www.leg.state.nv.us/Session/72nd2003/Bills/AB/AB431_EN.html

NV Energy’s total NEM PV installation capacity target between 2014 and 2025 is 250 MW. Under the new proposed incentive program, NV Energy will reduce the PV incentive levels when 100 MW have been installed. The levels take an additional step down after another 75 MW have been installed. The following table summarizes the proposed incentive levels:

Table 11: Proposed RenewableGenerations Incentive Levels

		Upfront Rebate ($/W)			PBI ($/kWh)		
Technology	Customer Class	First 125 MW	100-175 MW	175-250 MW	First 125 MW	100-175 MW	175-250 MW
Solar	Residential / Commercial / Industrial	0.400	0.275	0.175	0.043	0.030	0.019
	Public / Low Income	0.800	0.550	0.350	0.086	0.059	0.038
Wind	Residential / Commercial / Industrial	-			0.043*		
	Public / Low Income	-			0.086*		

*No 250 MW goal or incentive level reductions currently in place for wind.

The incentive levels are subject to change as a result of actual adoption levels and changes in installed capital costs.[9]

We estimate that the total RenewableGenerations incentive payouts for NEM systems installed through 2016 will be approximately $304 million ($2014).[10]

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[9] Docket No. 14-02004. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy: Annual Renewable Energy Plan for Program Period 2014-2015, Hearing Transcript at 304-307.

2.3 Analysis Framework

2.3.1 COST TEST OVERVIEW

This analysis evaluates the costs and benefits of the NEM generators from five perspectives established in the Standard Practice Manual (SPM). Each perspective is defined by a "cost test" and collectively they define a broad assessment of the cost-effectiveness. There is not a single correct cost test to use in general, each SPM cost test aims to answer a different question as follows:

- The *Participant Cost Test (PCT)* analyzes the financial proposition of purchasing and installing a NEM system from a NEM participant's perspective. If a customer's bill savings are greater than the customer's post-incentive capital costs paid, then the customer experiences a monetary gain from installing a NEM system.
- The *Ratepayer Impact Measure* (RIM) measures the impact of NEM on non-participating utility customers. The RIM test compares the utility avoided costs from not having to provide the energy generated by the NEM system (reduction in revenue requirement) to the incremental utility system costs such as incentives and program administration and the lost utility revenue due to reductions in NEM customer bills. If there is a net shortfall, over time in the next rate setting proceeding the utility would be allowed to increase customer rates to make up for the shortfall, which results in a cost-shift form participants to non-participants.
- The *Program Administrator Cost Test (PACT)* calculates the cost-effectiveness of NEM from the perspective of all customers of the

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[10] We assumed an average 21% capacity factor for PV, an average 2% capacity factor for wind installed through 2013, and an average 17% capacity factor for wind installed in 2014 and forward. We used NV Energy's weighted average utility-after tax WACC to calculate the net present value of the cost stream.

program administrator, the NV Energy utilities. Note that this cost test is also commonly known as the *Utility Cost Test (UCT)*. This test addresses the question, “Will customer bills need to increase because of NEM?” If NEM reduces the utility revenue requirement, or total cost of providing service, then the average customer bill including both participants and non-participants will decrease.

- The *Total Resource Cost Test (TRC)* captures the total direct monetary impact of NEM on the state of Nevada. The test includes the net impacts of participants, non-participants, and utility administrators. Cost shifts between parties within Nevada and benefits that cannot be directly monetized through existing channels are excluded from this analysis. Note that this test does include the net costs of emissions to the extent that emissions costs are embedded in energy prices and utility costs.
- The *Societal Cost Test (SCT)* aims to quantify the total impact of NEM on the state of Nevada when externalities are included. In this analysis, the SCT differs from the TRC only in its inclusion of the societal net health benefits due to a change in emission levels.

Table 12 describes the cost and benefit components of each of the cost tests. Each component is described in detail in Section 3. Note that some cost test components, such as customer bill reductions, are transfers from participants to non-participants. This occurs because lower bills for participants reduce the revenue the utility collects, and to the extent these bill reductions are greater than any cost-savings, the next utility rate case would increase rates to make up the shortfall, increasing bills of non-participants. Transfers may be treated as a cost in some tests and a benefit in others due to differences in the cost test perspectives.

Table 12: Benefit and Cost Components of Cost Tests

	Benefits	Costs
Participant Cost Test (PCT)	Customer Bill Reductions + Utility Incentives + Federal Tax Credits	NEM Generation System Costs
Ratepayer Impact Measure (RIM)	Utility Avoided Costs	Customer Bill Reductions + Utility Incentives + Utility Integration Costs + Utility Administration Costs
Program Administrator Cost Test (PACT)	Utility Avoided Costs	Utility Incentives + Utility Integration Costs + Utility Administration Costs
Total Resource Cost (TRC)	Utility Avoided Costs + Federal Tax Credits	NEM Generation System Costs + Utility Integration Costs + Utility Administration Costs
Societal Cost Test (SCT)	Utility Avoided Costs + Federal Tax Credits + Health Benefits	NEM Generation System Costs + Utility Integration Costs + Utility Administration Costs

Future costs and benefits are discounted back to 2014 dollars. The PCT, RIM, PACT, and TRC all use the average utility after-tax weighted average cost of capital (WACC) for NVE North and NVE South of 6.8% as the discount rate for this net present value (NPV) calculation. We use a lower societal discount rate of 3% to account for the societal cost test that includes externalities. Using a lower discount rate is standard practice in the SPM and reflects a longer-term emphasis on costs and benefits from a societal perspective and a lower cost of borrowing of the state than the utility. This notion of using a lower social discount rate relative to a private discount rate is well established in the literature.[11]

We say that a program "passes" each of these five tests if the present value of the relevant benefits is greater than the present value of the relevant costs. Table 13 summarizes the interpretation of each set of cost test results.

Table 13: Cost Test Result Interpretations

	Benefits GREATER than Costs	Benefits LESS than Costs
Participant Cost Test (PCT)	NEM customers spend less on utility bills than had they not installed NEM	NEM customers spend more on utility bills than had they not installed NEM
Ratepayer Impact Measure (RIM)	Average utility rates decrease, decreasing bills of non-participants	Average utility rates increase, increasing bills of non-participants
Program Administrator Cost Test (PACT)	Total bills (revenue requirement) collected by the utility decrease	Total bills (revenue requirement) collected by the utility increase
Total Resource Cost (TRC)	There is a positive economic benefit to the state of Nevada	There is an economic cost to the state of Nevada
Societal Cost Test (SCT)	There is a positive economic benefit to the state of Nevada INCLUDING benefits of criteria pollutant reductions	There is an economic cost to the state of Nevada INCLUDING benefits of criteria pollutant reductions

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[11] See generally, http://yosemite.epa.gov/ee/epa/eerm.nsf/vwAN/EE-0568-06.pdf/$file/EE-0568-06.pdf

2.3.2 RESULTS FRAMEWORK

A number of policy and program changes that substantially impact the cost test results have recently come into effect or are expected to come into effect by 2016. In order to accurately capture these effects, we display results in three time period groups, with each time period capturing a specific set of policies and program rules. The main policy changes are:

- In 2014, the RenewableGenerations incentive program is being redesigned with significantly lower incentive levels and open, on-going availability. This new design replaces the prior lottery-based system, under which utility incentives were only available to those that won the lottery. The new design also includes more stringent performance requirements for wind systems and replaces the old capacity-based incentive with a PBI for wind and large PV systems.
- Effective starting in 2014, NV Energy has adjusted the NEM tariff such that compensation for exports to the grid no longer include a payment for public purpose charges. This reduces the compensation for NEM systems somewhat. NEM generation that displaces on-site load still benefits from reduced public purpose charges.
- In 2016, the credits towards the Nevada RPS for solar generation will no longer be counted with a multiplier on production. All eligible generation will be counted towards the RPS on an equal basis. Prior to 2016, utility-sited solar generation is awarded a 2.4 multiplier towards RPS compliance, and distributed solar generation is awarded a 2.45 multiplier.

Figure 3 summarizes the significant policies and program rules that characterize each of the time periods analyzed.

Figure 3: Vintage Breakdowns for Analysis

All Vintages (2004-2016 NEM systems)

- Capital costs, the utility incentive program, treatment of public purpose charges , and the RPS policy vary across time

Existing Installations (through 2013)

- High NEM system pre-incentive capital costs
- High utility incentive levels, awarded using a lottery-based system

2014/2015 Installations

- Utility incentive program expanded and changed; Incentive levels reduced; upfront capital costs replaced with performance-based incentives for wind and large solar NEM systems; and incentives now offered on a first-come first-served basis
- Reduced capital costs
- Exports to the grid no longer receive bill credits for public purpose charges

2016 Installations

- RPS multiplier is eliminated for systems installed in or after 2016, decreasing the amount of utility-scale RPS capacity that NV Energy can avoid installing through each unit of NEM generation

2.3.3 GENERATION ATTRIBUTABLE TO THE NEM PROGRAM

This analysis attributes the costs and benefits of all NEM generation to the NEM program. Some studies attribute only exported electricity generation to the program; for example, the 2013 California Public Utility Commission NEM study includes both the all generation and the export only electricity in its framework.[12] To the extent that NEM compensation enables the viability of DG installations, all generation is the appropriate measure to use for cost and benefit accounting. An export only estimate was not performed in this study for two reasons: (1) the approach taken is as required by statute, and (2) the underlying customer load shapes required to conduct the export only analysis were not available.

2.3.4 CONSIDERATION OF SB 123

To facilitate the transparency of this analysis, we used publicly-available, PUCN-approved data whenever possible. Many of the underlying assumptions and data used in this study were developed during the utility resource planning process at the PUCN in 2012 and 2013. Consequently, we cannot incorporate any policies into our study that were not incorporated in this planning process. In particular, we exclude impacts of Senate Bill (SB) 123 from this analysis.

The enactment of SB 123 in 2013 potentially changes a number of assumptions related to the NVE South system. Among other items, SB 123 requires NVE South to retire or eliminate not less than 800 MW of coal-fired electric generation by December 31, 2019. SB 123 further provides for NVE South to construct, acquire, or contract for 350 MW of renewable energy generating capacity through solicitations issued between December 2014 and December 2017. SB 123 also provides that NVE South construct or acquire 550 MW of company-owned electric generating capacity, which could be a combination of renewable and

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[12] The 2013 CPUC NEM evaluation is available for download at: http://www.cpuc.ca.gov/PUC/energy/Solar/Comments_on_the_Draft_NEM_Report.htm.

conventional electric generating capacity. These represent significant changes to the NVE South system.

At the time data was collected for this study, no comprehensive analyses of the impacts of SB 123 on the NVE South system had been filed with the Commission for review. Consequently, many of the inputs used in this study, including energy and capacity costs, fuel use, utility emissions, and forecasted RPS shortages do not reflect the impacts of SB 123. In the absence of any detailed analysis of the effects of SB 123, incorporating the impacts of these factors would amount to nothing more than speculation; the impacts are therefore not included in this study.

3 Methodology

3.1 Data and Participant Grouping

This analysis draws on individual installation data of more than 3,300 existing NEM generators installed through 2013. For most generators, data on customer class, DG technology, utility rate tariff, location, install year, and installation capacity were available. For generators that had received utility incentives, historical monthly generation totals and installed costs were also available.

All calculations were performed on as granular a level as data allowed. In aggregating the results, systems were grouped along the following dimensions:

- Customer Class
    - Residential
    - Non-residential
- Utility
    - NVE North
    - NVE South
- Generator Technology Type
    - PV
    - Wind

- Utility Incentive Status
    - Incentivized
    - Non-Incentivized

We chose these dimensions and categories in order to represent a manageable number of total results while still providing insight into how impacts vary across key customer groups. Aggregating the data in this manner produced a total of 24 groups, where each group holds a single attribute from each dimension.

Note that we frequently refer to NEM wind systems installed prior to 2013 as *existing wind*, and we call wind in years 2014 through 2016 *forecasted wind*. This distinction reflects proposed changes to NV Energy's wind incentive requirements in 2014 and beyond. The 2014 requirements ensure that new wind systems will only be installed in areas with relatively high wind speeds. Consequently, new wind exhibits higher capacity factors, on average, than existing wind. Capacity factor is defined as the total amount of energy produced by a power plant over a given period of time relative to the amount of energy that would have been produced if the power plant were operating at its full nameplate capacity throughout the entire time period. In general, the capacity factors of renewable energy systems are limited by availability of solar and wind resources.

The expected impacts of the changes in NV Energy's NEM incentive program for NEM wind systems are explained in more detail in Section 3.2.2.

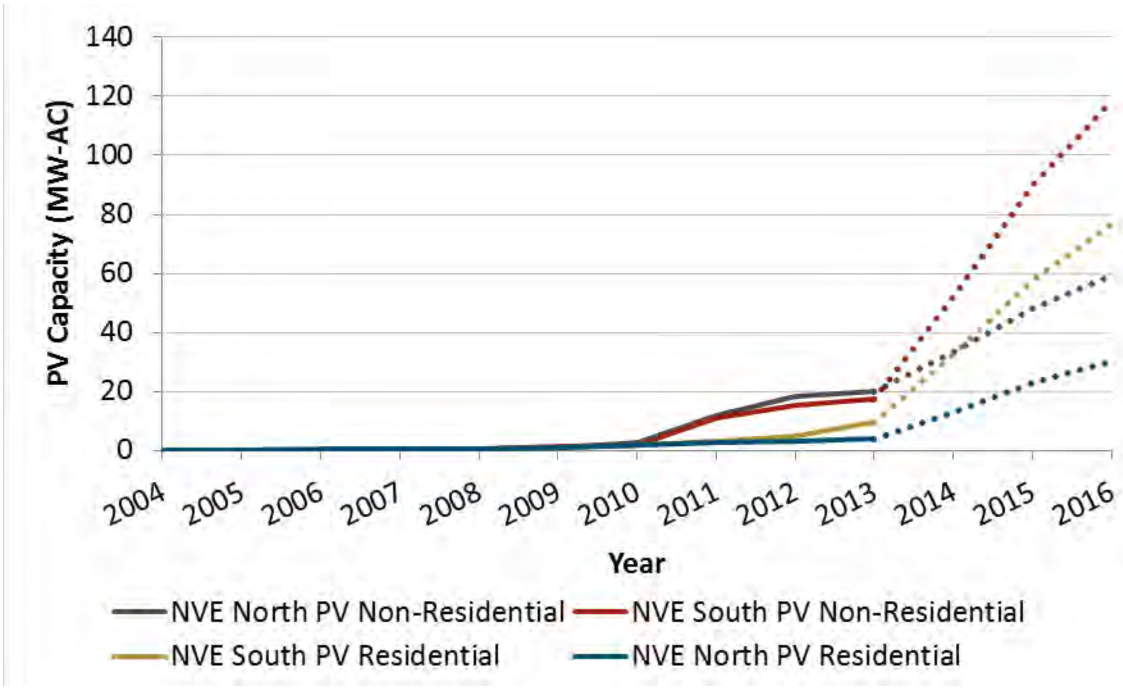
3.2 Installed NEM Capacity

We drew on NV Energy's database of existing net metered systems to determine the total installed NEM capacity in Nevada from 2004 through 2013. Forecasted installations from 2014 through 2016 were based on NV Energy's internal projections.

3.2.1 SOLAR INSTALLATION FORECAST

NV Energy's RenewableGenerations incentive program has a targeted goal of incentivizing 250 MW of NEM PV capacity installations by 2020. Current PV installed capacity sits just over 50 MW, and installations have increased substantially in recent years. NV Energy has a goal of incentivizing 250 MW of PV capacity between 2014 and 2025. NV Energy expects about 84% (211 MW) of this capacity goal to be reached by the end of 2016. In addition to the 250 MW of incentivized NEM PV capacity, NV Energy expects that an additional 23 MW of non-incentivized NEM PV capacity will come online by the end of 2016. Figure 4 shows the cumulative installed PV trajectory through 2016 by utility and customer class.

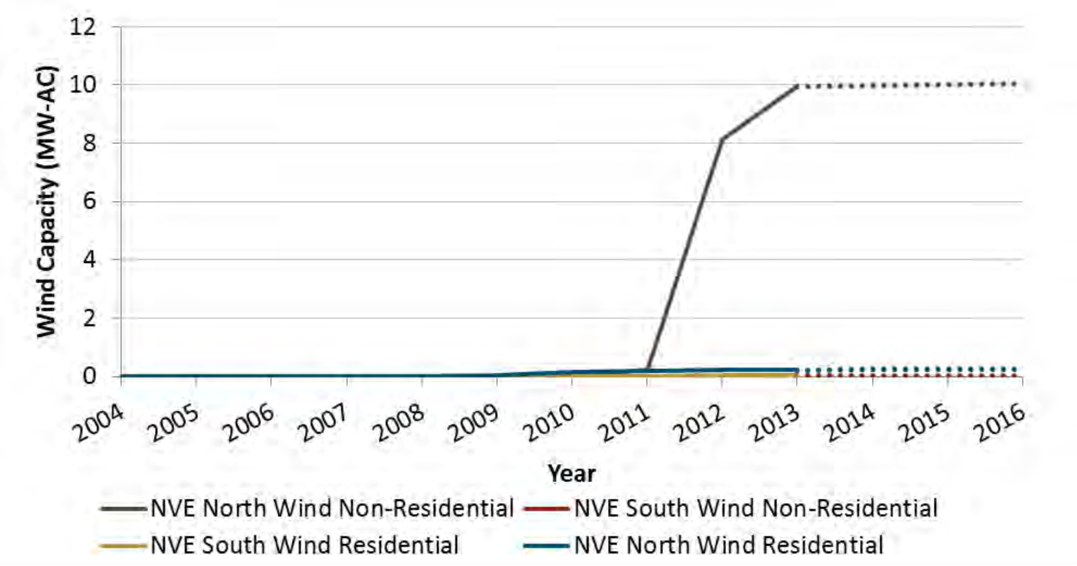
Figure 4: Historical and Forecast Cumulative NEM PV Installed Capacity



3.2.2 WIND INSTALLATION FORECAST

Historically, nearly all wind installations in Nevada have participated in NV Energy's RenewableGenerations incentive program. The utility's proposed changes to the incentive structure in early 2014 require all wind installations receiving incentives to be located in regions with a minimum average annual wind speed of 10 miles per hour (mph). The proposal significantly changes the DG wind outlook in Nevada, since most existing DG wind installations are located in areas with average wind speeds far below the new minimum level. Because of these new requirements, NV Energy forecasts almost no growth in installed NEM wind capacity through 2016. Regions of Nevada that meet the requirement are not where people generally live. Figure 5 shows historical and forecasted installed wind capacity in Nevada.

Figure 5: Historical and Forecast NEM Wind Cumulative Installed Capacity



3.2.3 TOTAL NEM CAPACITY

Nevada's net metering policy places a cap on installed capacity equal to 3% of statewide peak load. To approximate the level of the cap in 2016, we aggregated NVE North and NVE South's forecasted gross peak loads, as reported in NV Energy's 2013 IRP.[13] Figure 6 shows the total historical and forecasted NEM installations in the state through 2016. Note that the NEM installation forecast exceeds the 3% statutory cap.

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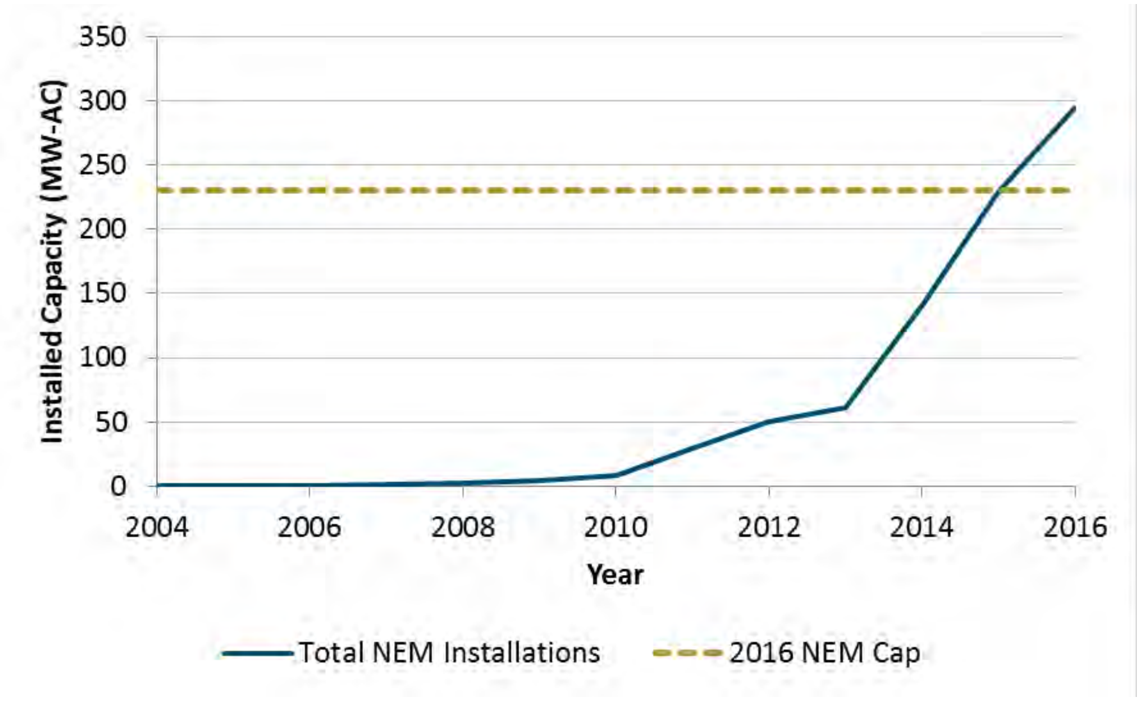
[13] 2013 NVE IRP can be downloaded at: https://www.nvenergy.com/company/rates/filings/IRP/SPPC_IRP/

Figure 6: Total Nevada NEM Installed Capacity



Nevada's net metered systems also include a very small number of hydroelectric and geothermal installations. We exclude these resources from our analysis due to lack of performance data. The total existing installed capacity of DG hydro and geothermal in NV Energy's territory is less than 0.5 MW. Therefore, excluding them does not have a material impact on the results.

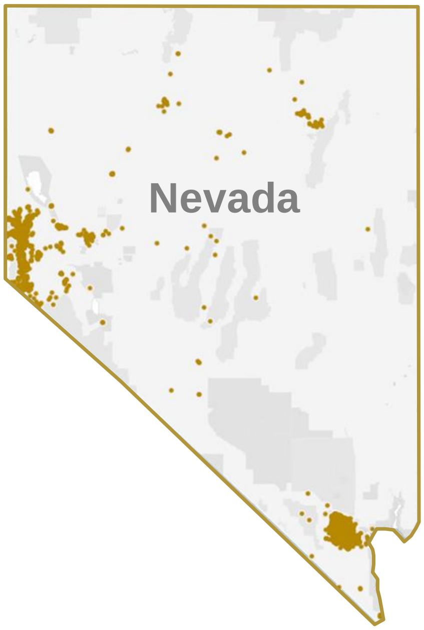
3.3 Renewable Output Simulation

Our calculations of bill savings and avoided costs depend on the hourly generation profiles of DG resources. Real hourly generation data is not available for Nevada's net metered systems, so we developed simulated generation profiles for each NEM system. We benchmarked our simulations to match the actual monthly NEM generation of each system, as provided by NV Energy. Special emphasis was placed on matching the summer months, when Nevada's capacity costs are high. It is especially important to accurately estimate NEM generation during these periods of high $/MWh avoidable utility system costs.

3.3.1 SOLAR SIMULATIONS

Using customer service addresses, we mapped each NEM customer-generator to a 10 km^2 geographic block from National Renewable Energy Laboratory's (NREL) Solar Prospector database. Figure 7 shows the location of all 3,100+ PV NEM generators installed as of 2013.

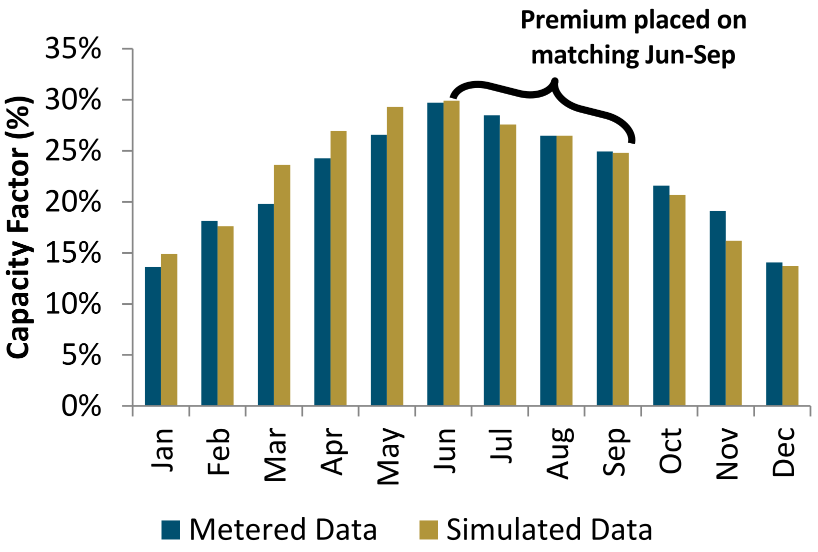
Figure 7: Map of Existing NEM Solar Generators



We then used the Solar Prospector database to generate hourly solar radiation data for a typical meteorological year (TMY) in each location. We converted the solar radiation data to hourly energy output using industry standard simulation equations available in NREL's System Advisor Model (SAM). We modified various scalars and parameters in SAM to calibrate the simulated output to historical metered data.

The resulting simulated total annual AC capacity factor of all PV generation was 22.6%. The actual reported annual capacity factor was 22.2%. The slight discrepancy is due to the premium on matching capacity factors in the summer months. Figure 8 shows total monthly capacity factors for both metered and simulated PV data.

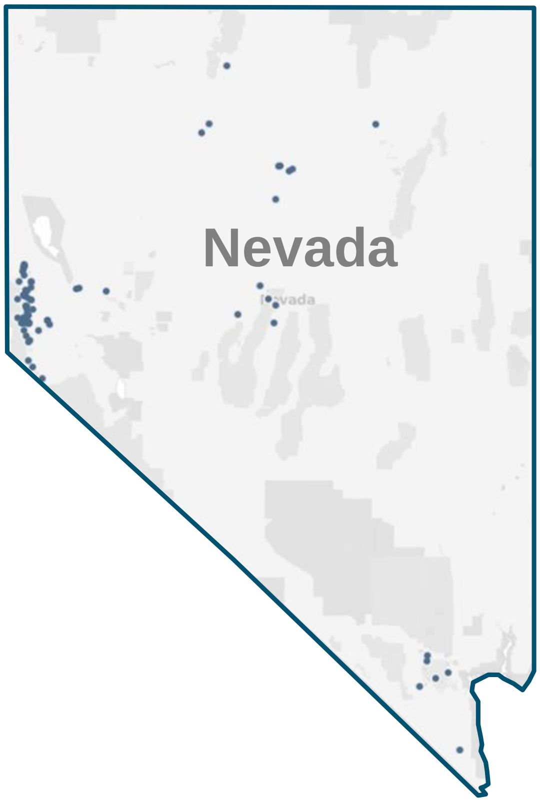
Figure 8: Monthly Capacity Factors for Metered and Simulated PV Output



3.3.2 WIND SIMULATIONS

We simulated hourly wind generation for each wind installation using NREL's Western Wind Resource Dataset. Figure 9 shows the location of all 164 Nevada wind NEM generators as of 2013.

Figure 9: Map of Existing Wind Generators



We mapped each NEM generator to the nearest wind station ID in the NREL database. Each station ID dataset includes one year of ten-minute interval wind speeds simulated at 100 meters, a typical utility scale turbine hub height. We estimated the likely hub heights of existing NEM wind systems using a simple correlation between turbine capacity and typical hub height. Next, we scaled the 100 meter wind speeds down to our estimated hub heights using the wind profile power law,[14] a common industry technique for scaling wind speed from one hub height to another. Using the capacity of each NEM wind turbine, we used an appropriate power curve to translate wind speed into hourly energy output. We used a scaling factor to adjust the input wind speed shapes until the simulated annual capacity factor exactly matched the historical metered annual capacity factor of 2.5%. We used this method to simulate generation for all wind systems installed through 2013.

The historic capacity factors of existing NEM generators in Nevada are extremely low. Recent changes to NV Energy's RenewableGenerations program require all future DG wind to be installed in locations with a minimum average annual wind speed of 10 mph. To simulate wind generation profiles for systems installed in 2014 and beyond, we scaled the NREL wind data to achieve a 10 mph average speed. We then used the power curves described above to create a separate set of profiles for forecasted wind systems. The profiles used for future wind generation have an average annual capacity factor of 17.5%.

3.4 Bill Savings

Bill savings are the difference between what a NEM customer's bill would be without NEM generation and the same customer's bill with NEM generation. To quantify these savings, we created a custom bill calculator using current Nevada

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[14] We assumed an alpha of 1/7.

electric utility rates and the renewable output simulation profiles described in Section 3.3. We modeled bill savings for each individual NEM installation based on customer rate information provided by NV Energy. Figure 10 shows how installed NEM capacity as of 2013 is distributed across rate classes and technology types, while Table 14 lists a description of each rate class.

Figure 10: Existing NEM Installations by Rate Class and Technology

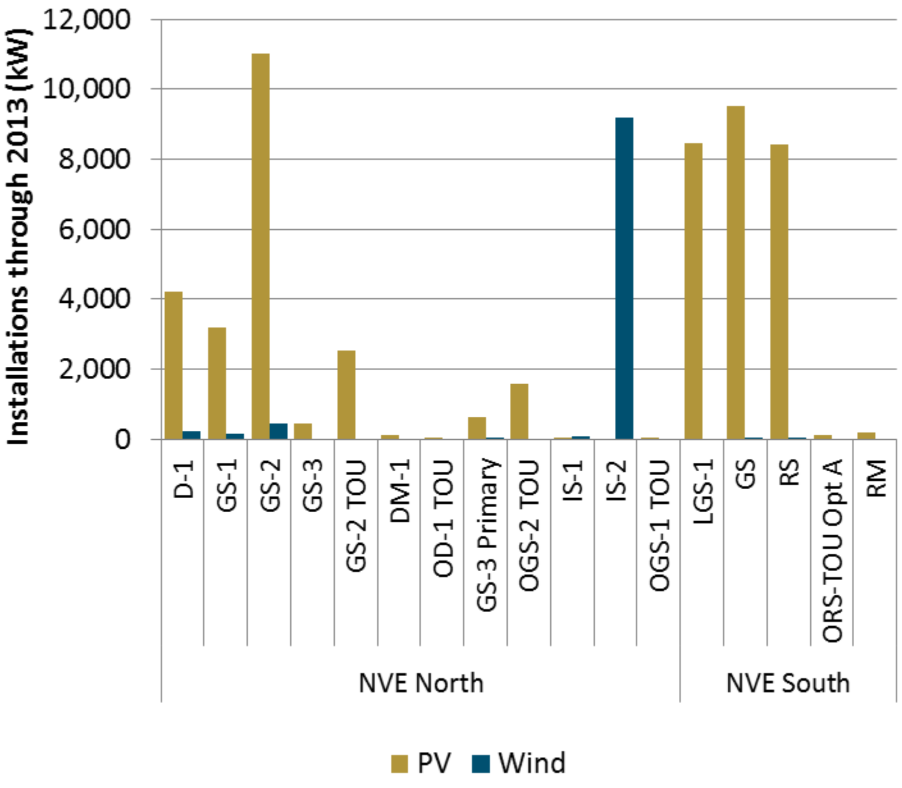
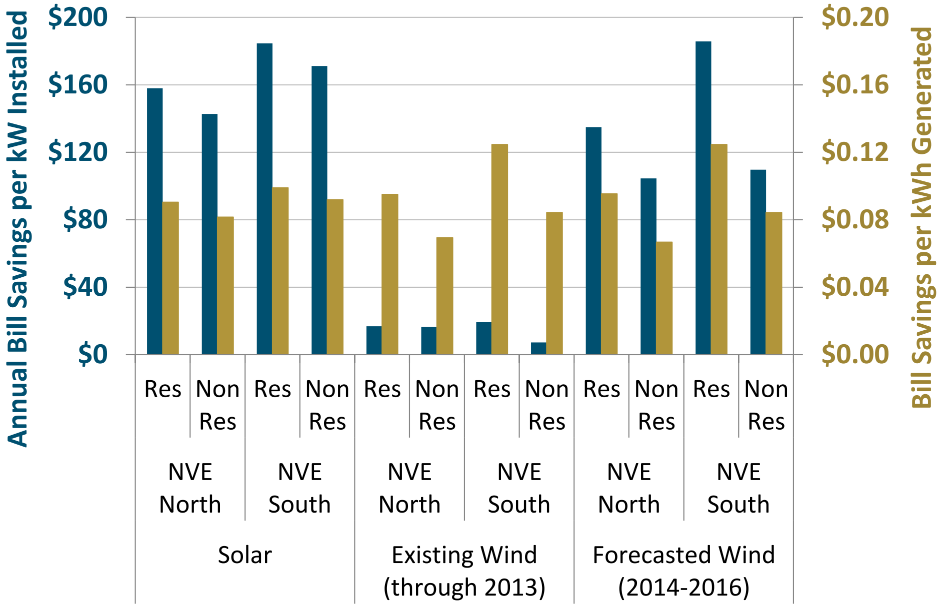


Table 14: Description of NV Energy Rate Classes

D-1	Single Family Residential
GS-1	Small Commercial
GS-2	Medium Commercial
GS-3	Large Commercial
GS-2 TOU	Medium Commercial Time-of-Use
DM-1	Multi-Family
OD-1 TOU	Optional Residential Time-of-Use
GS-3 Primary	Large Commercial High Voltage
OGS-2 TOU	Optional Medium Commercial Time-of-Use
IS-1	Irrigation Service
IS-2	Interruptible Irrigation Service
OGS-1 TOU	Optional Small Commercial Time-of-Use
LGS-1	Large Commercial
GS	Small Commercial
RS	Single Family Residential
ORS-TOU Opt A	Optional Single Family Residential Time-of-Use
RM	Multi-Family

Using the utility tariff assigned to each NEM generator, we calculated annual bill savings by multiplying the output of each NEM generator in every hour of the year by the corresponding electric rate. The blue bars in Figure 11 show the outputs of the bill calculator in annual savings per kW of installed capacity in 2013. The bill savings for existing wind are very low due to the low capacity factor of these systems. The gold bars represent bill savings per kWh generated. Since these values are normalized for generation, capacity factors do not affect these values. Differences in bill savings across categories are predominantly due to differences in rate design, although NEM generation profiles also play a role. These values change over time in our analysis as NEM systems gradually degrade and electric retail rates escalate.

Figure 11: Bill Savings by Install Capacity and Annual Generation



Our base case bill savings estimates do not include any reductions in demand charges that might result from NEM generation. The demand charge portion of a customer's bill is calculated by multiplying a fixed $/kW charge by the customer's peak load during a specific time period, typically the billing period. Less than 10% of Nevadan NEM systems and 40% of installed NEM capacity are currently on rate tariffs with demand charges (generally only large commercial customers in Nevada pay demand charges). The share of NEM participants paying demand charges in our analysis declines even further beyond 2013 because our forecast includes residential NEM installations outpacing non-residential installations in the future.

We do not have data on customers' underlying load shapes, so we cannot estimate how NEM generation would affect peak load of commercial customers with demand charges. Overall, NV Energy’s commercial load peaks late in the day, so we infer that peak load and PV generation are not very coincident for most commercial customers. While assuming no demand charge reduction is a conservative assumption, it is most likely that the true demand charge reduction is not very large. Therefore, we perform a sensitivity to demonstrate how this assumption may impact the results.

3.5 Avoided Costs

Avoided costs represent the value that a distributed resource provides to the electric grid. Electricity generation from NEM installations serves utility load, allowing the utility to reduce its overall costs of providing service. In other words, for every kWh of energy generated by a NEM system, the utility has to produce or purchase one less kWh from a dispatchable fossil fuel plant. Thus, the utility “avoids” the variable cost of generating that kWh. Enumerated below, there are multiple other cost components that the utility avoids through NEM generation.

We used utility data from NV Energy’s 2013 IRP to develop hourly avoided costs for NV Energy’s two subsidiaries. The planning horizon used in the 2013 IRP spans the years from 2014 through 2043, which captures the full lifetimes of all NEM systems included in this analysis. Using hourly avoided costs captures the varying value to the grid of energy produced during periods of high demand relative to periods of low demand. Section 7.2 in this report’s appendix describes our avoided cost methodology, including all key assumptions, in more detail.

We build up hourly avoided costs by combining several different cost components. Table 15 describes each cost component and the data source used to generate values in each category. Section 7.3 in the Appendix includes additional information about avoided cost calculation methodology by component.

It is important to note that we do not include distribution capacity avoided costs in the base case. This is due to the high generation intermittency of the relatively small number of PV and wind NEM systems that lie behind any single distribution feeder. This intermittency precludes utility distribution planners from taking this capacity into account when designing the distribution system. However, we do measure the impact of including distribution capacity avoided costs through sensitivity analysis.

Table 15: Avoided Cost Components and Data Sources

Component	Description
Energy Generation	Estimate of hourly marginal wholesale value of energy, including the regulatory price of carbon dioxide emissions. Source: Production simulation runs from NV Energy's 2013 IRP. These simulations produced energy prices for each utility from 2014 through 2043. The energy prices include a carbon price beginning in 2018.
Distribution Losses	Energy generation avoided costs are adjusted to account for losses between the point of wholesale transaction and the point of delivery. Source: Losses as a function of hourly load from NVE North's 2013 General Rate Case (GRC) and NVE South's 2011 GRC.
Ancillary Services (A/S)	Marginal cost of providing spinning reserves for electricity grid reliability. Source: NV Energy provided a summary of total energy production cost spending and spinning reserve spending from 2014 to 2018. On average, spinning reserves represented 0.5% and 2% of total energy spending over that time period for NVE South and NVE North, respectively. We used those proportions to calculate A/S avoided costs as a share of energy generation avoided costs.
Transmission Capacity	Cost of expanding transmission capacity to meet customer peak loads. The annualized cost of transmission is grossed up to include transmission level losses (assumed to equal distribution losses plus 2%) and then allocated to individual hours using the hourly Normalized Probability of Peak (POP). Source: Annualized cost of transmission and annual hourly POPs from NV Energy's most recent GRCs. POPs were provided for years 2014-2043.
Distribution Capacity (Used as Sensitivity Only)	Cost of expanding distribution capacity to meet customer peak loads. The annualized cost of distribution upgrades scaled up by distribution losses and allocated to individual hours using the POP. These values were provided on an average system-wide $/kW basis for each utility. Source: Annualized cost of distribution and POPs from NV Energy's most recent GRCs.
System Capacity	Marginal cost of meeting system peak loads. While NV Energy has a capacity surplus, this is equivalent to the fixed O&M cost of a capacity resource, assumed to be a natural gas combustion turbine because of its low cost. After NV Energy would otherwise need to build new capacity, the capacity cost represents additional cost of building new generation capacity above what can be earned in energy and ancillary service markets. The annualized capacity value is grossed up to include transmission level losses and allocated to individual hours using hourly Normalized Loss of Load Probability (LOLP). Source: Annualized cost of system capacity and annual hourly LOLPs from NV Energy's most recent GRCs. LOLPs were provided for years 2014-2043.

The following figures show average 2014 monthly avoided costs for NVE North and NVE South:

Figure 12: NVE North Average Monthly Avoided Costs

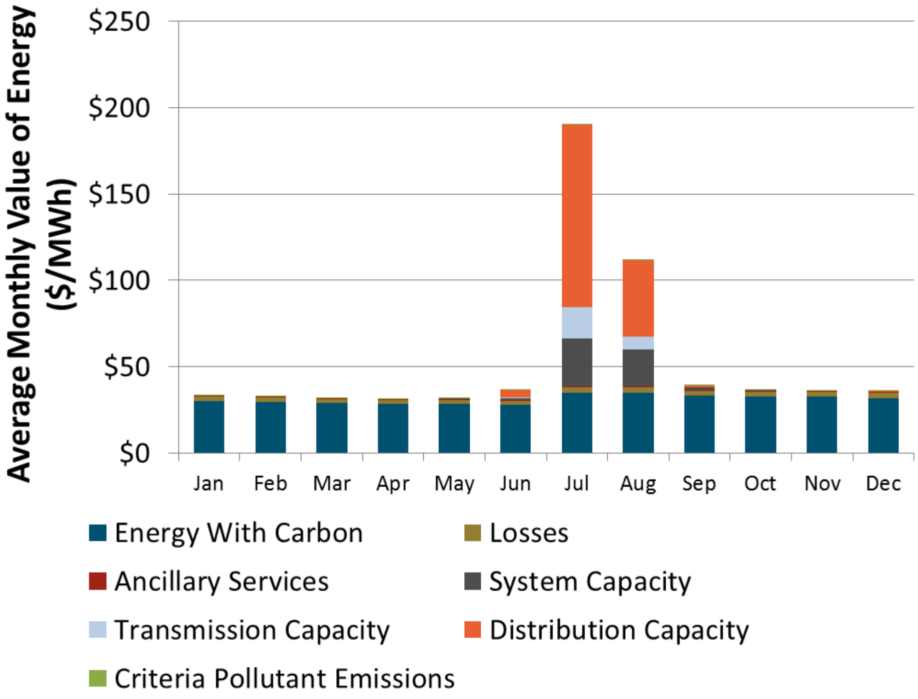
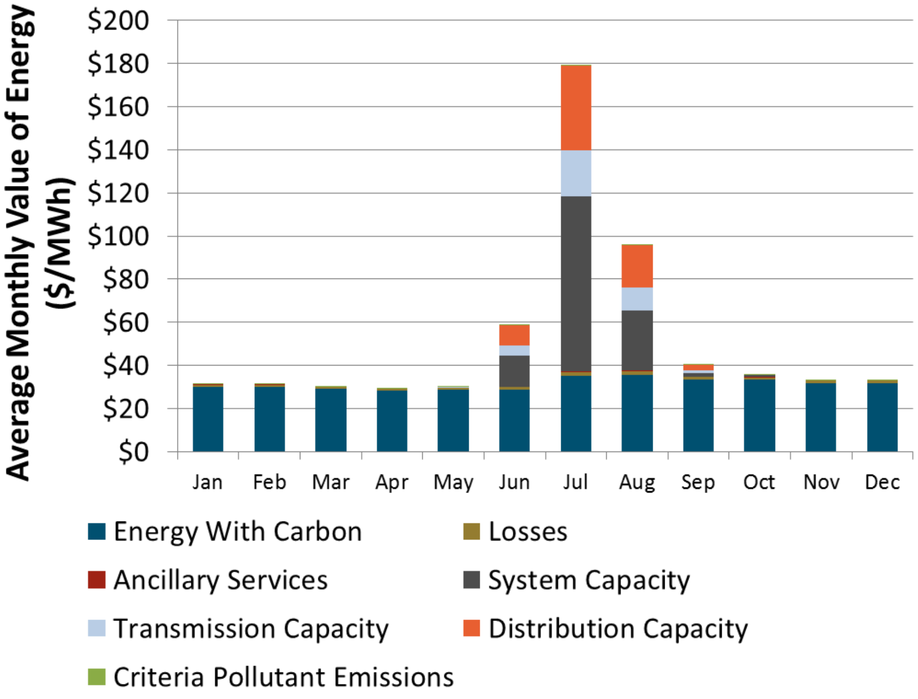


Figure 13: NVE South Average Monthly Avoided Costs



To calculate the total avoided costs of a net metered system, we multiply the hourly simulated generation profiles by the hourly avoided cost values. The sum of the hourly values represents the total annual avoided cost value of the NEM installation.

3.6 RPS Compliance Value

3.6.1 RPS COMPLIANCE VALUE OVERVIEW

The RPS compliance value is the value that NEM provides by preventing or delaying utility purchases of renewables that would otherwise be needed to comply with Nevada's RPS. NEM generation provides NV Energy with RPS compliance value in two ways: (1) by providing energy credits for RPS compliance; and (2) by reducing utility load and, thereby, NV Energy's RPS compliance obligation. RPS value is an avoided cost component. We present the RPS avoided costs separately from the other avoided cost components in the results because we want to highlight how the RPS policy impacts avoided cost value.

As part of the RenewablesGeneration program, NV Energy receives the portfolio energy credits (PECS), measured in thousands of PECS (kPCs), associated with generation from incentivized NEM systems. NV Energy receives 1 kPC for each MWh of incentivized NEM wind generation. Because of Nevada's 2.45 RPS solar DG multiplier, NV Energy receives 2.45 kPCs for each MWh of NEM solar generation from systems installed through 2015. PV systems installed after 2015 do not receive a multiplier.

In addition, incentivized and non-incentivized NEM generation provides a load reduction RPS value. The Nevada RPS establishes NV Energy's annual compliance obligations as fixed percentages of retail sales. As a result, any NEM generation that reduces net retail sales reduces NV Energy's compliance obligation. NV Energy is required to meet at least 25% of its retail load by 2025, meaning that 1 MWh of non-incentivized NEM generation in 2025 would decrease NV Energy's RPS compliance obligation by 0.25 kPC in that year.

3.6.2 PORTFOLIO ENERGY CREDIT CALCULATION

Nevada's energy portfolio standard permits banking of excess kPCs. NV Energy is required to attempt to sell any kPCs in excess of 125% of the compliance obligation for the given year. In the absence of information regarding the potential market for kPCs, we assume that there is no market for the kPCs and therefore allow unlimited banking. Every kPC from NEM generation receives some compliance value, but the value may accrue in a later year than the one in which the generation actually occurs.

We calculate the RPS compliance obligation using load and resource data from the NV Energy's 2013 RPS compliance report.[15] The annual net shortage or surplus of kPCs without NEM generation is calculated for each utility. The contribution of NEM generation is then allocated to compliance years chronologically based on these annual shortfalls. kPCs from all NEM technologies, customer classes, and customer utility incentive status (incentivized or non-incentivized) are allocated to compliance years proportionally.

The value of using a PEC to comply with the RPS compliance obligation in a given year is calculated as the cost of obtaining one PEC from utility-sited PV. Because of Nevada's 2.4 RPS multiplier for utility-sited solar installed through 2015, the

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[15] NV Energy, Portfolio Standard Annual Report for Compliance Year 2013, available at: https://www.nvenergy.com/renewablesenvironment/renewables/images/2013ComplianceReport.pdf

value of 1 kPC is the cost of obtaining 2.4 MWh of new, utility-scale PV in 2014 and 2015. After 2015, the value of 1 kPC is the value of 1 MWh of utility-scale PV. The inputs used to calculate the value of utility-scale PV are described in more detail in Section 7.2 of the Appendix.

3.7 Program Costs

Program costs are the costs to the utility of implementing and maintaining the NEM program. NV Energy's program costs include a one-time setup cost associated with installing a bi-directional meter necessary for net metering, as well as ongoing annual costs of staff and other expenses required to maintain the program. Using spreadsheet data provided by the utility, we estimated the initial, one-time costs of installing a NEM system in NVE North and NVE South service territories to be \$17.28/kW and \$12.63/kW, respectively. While these costs are more a function of absolute number of system installations as opposed to capacity, these cost estimates are unitized in \$/kW so that they can be applied to installation forecasts, which are defined in kW. We estimate ongoing costs of maintaining the NEM program to be \$115,000 annually. Ongoing costs are allocated between NVE North and NVE South in proportion to total installed NEM capacity in each year. Table 16 shows the NEM program costs used in our analysis.

Table 16: NEM program costs

	NEM Program Costs (2014$)
Total annual fixed cost (ongoing)	$115,000
NVE North *$/kW installed ($2014)* (one-time cost at installation)	$17.28
NVE South *$/kW installed ($2014)* (one-time cost at installation)	$12.63

3.8 Integration Costs

Wind and solar energy are inherently non-dispatchable, intermittent resources. The utility incurs additional operational costs when it acts to adjust to sudden changes in renewable output, referred to as integration costs. These costs typically manifest through increases in regulation reserve requirements, load following reserve requirements, and other ancillary services. In other words, the utility must keep more back-up generation online in case the energy output from the NEM systems unexpectedly decreases.

After conducting a literature review of several renewable integration cost studies in the western US,[16] we selected an integration cost adder of $2/MWh, applied to all NEM generation. Estimates within these studies range from

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[16] *Large-Scale PV Integration Study*, Navigant Consulting, 2011
Integrating Solar PV in Utility System Operations, Argonne National Laboratory, 2013
Solar Photovoltaic Integration Cost Study, Black and Veatch, 2012
Distributed Generation Study, Navigant Consulting, 2010

$0/MWh to $18/MWh while the vast majority of estimates were in the single digits. We intentionally selected an integration cost lower that those reported in many studies for two primary reasons: 1) Nevada's renewable energy penetration level is lower than the penetrations in many of the western states studied, and 2) most of the available literature focuses on large-scale solar installations, which present larger intermittency problems than DG because it is less geographically diverse.

The scale of forecasted NEM in Nevada is small enough that there is no substantial need for in-depth studies on voltage risks or distribution upgrades to accommodate backflow. The forecasted NEM capacity is only 3% of Nevada's peak demand. FERC's Small Generator Interconnection Process[17] and California Rule 21[18] use a 15% penetration trigger for in-depth interconnection studies. DG penetration levels lower than 15% of peak circuit load are not considered at risk for causing voltage or backflow issues. Moreover, high DG penetration studies in Hawaii find that much larger penetration levels do not cause voltage issues. Even when Kauai Island Utility Cooperative supplies 90% of distribution load with PV during the day, voltage remains within the +/- 5% tariff limit.[19]

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[17] FERC SGIP § 2.2.1.2

[18] See http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/rule21.htm

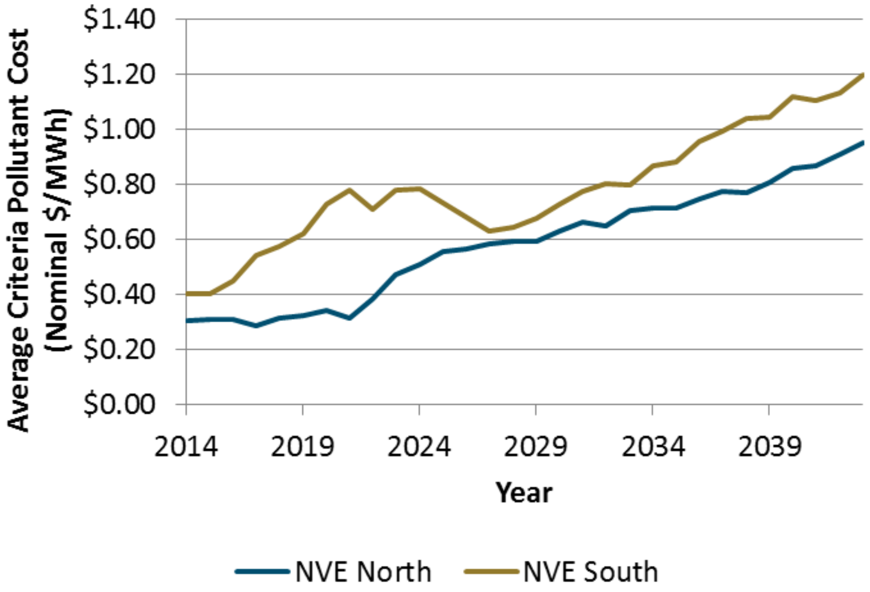
[19] Bank, J, B. Mather, J. Keller, and M. Coddington (2013). "High Penetration Photovoltaic Case Study Report." National Renewable Energy Laboratory Technical Paper.

3.9 Societal Benefits

This report includes a SCT analysis, which seeks to quantify the health benefits associated with renewable distributed generation. We used criteria pollutant health impact costs from NV Energy's 2013 IRP to evaluate the monetary health net benefits of avoiding or increasing fossil fuel combustion. Because of Nevada's RPS, NEM generation reduces utility-sited renewable generation that would have otherwise been built to meet the RPS obligation. We include the foregone health benefits associated with this reduced utility-sited renewable generation in our calculations in the SCT.

The IRP reports total portfolio costs of nitrous oxides, particulate matter, sulfur dioxide, and mercury for NVE North and NVE South, from 2014 through 2043. Using those values and the IRP's forecast of total utility generation in each year, we calculated the average costs per MWh of the combined health impacts of all of the pollutants. We calculated one average $/MWh of NEM generation cost and another $/MWh of utility-sited renewable generation cost. These costs only vary due to losses. Figure 14 shows the average annual total air emission cost per MWh of NEM generation for each utility.

Figure 14: Average Total Air Emission Cost per MWh of NEM Generation



We assume that every MWh of thermal generation emits the average annual criteria pollutant quantities. Data was not available to determine marginal emissions factors, so we use average emission cost as a proxy for marginal emission cost. In reality, the avoided criteria pollutant cost attributable to avoided thermal generation depends on the emissions factors of the displaced marginal generator in every hour.

Note that the health impacts rely heavily on uncertain assumptions about the societal cost of criteria pollutant emissions.

3.10 DG Installation Costs

NEM participants have the option of purchasing their DG installations outright or contracting with a third party system owner and installer. Participants sign a PPA, in which the third party owns the system and the participant purchases the generated energy. Over time, the third party ownership model has become increasingly common, likely because it presents little financial hurdle and relieves customers of maintenance obligations.

As a simplifying assumption, we assume that all NEM systems are installed and financed through a third-party provider where the customer purchases generated electricity over the lifetime of the system. We expect the third-party provider ownership model to be the most common form of ownership going forward. For systems installed in the past using different financing mechanisms, this is a simplifying assumption that enables a cost-effectiveness analysis without reconstructing the individual financing of historical systems or evaluating historical bill savings and avoided costs. We believe this a reasonable simplification because this analysis aims to inform the NEM policy going forward and not necessarily reconstruct cost-effectiveness of systems already installed for past years.

We use a pro forma model to convert upfront installation costs, operations and maintenance (O&M) costs, tax credits, and utility incentives into an expected PPA price paid by the NEM participant to a third party installer. The model takes into account the tax benefits and financing costs incurred by the third party owner. The pro forma methodology and inputs are described in more detail in Section 7.2 in the Appendix.

3.10.1 CAPITAL COSTS

To calculate historical capital costs, we used RenewableGenerations program data provided by NV Energy. Excluding outliers and missing data, we used the average installed cost for each customer group to represent historical installation costs.[20]

3.10.1.1 Solar Cost Forecast

The solar cost forecast was originally developed for the Western Electricity Coordinating Council (WECC) in December 2013. We compiled average historical PV costs from various public sources, and we calculated state-specific scale factors for each state in the western region. According to the WECC study, Nevada has historically reported lower rooftop solar costs than other western states. With precedence from the WECC model, we adjusted PV costs in the state assuming the costs of 89.7% of the western state average.

To forecast future prices, we then applied learning curves to the average historical PV prices developed. Learning curves are used to describe an observed empirical relationship between installed PV capacity and PV costs. The learning rate defines the expected decrease in costs with every doubling of experience. We assumed a 20% learning rate for PV modules and a 15% learning rate for balance of systems (BOS). Using the International Energy Agency (IEA) Medium-Term Outlook forecast of global installations, those learning rates mean that, when the global installation level doubles, PV module prices drop 20% and BOS costs decrease 15%. All of these assumptions were agreed upon through an

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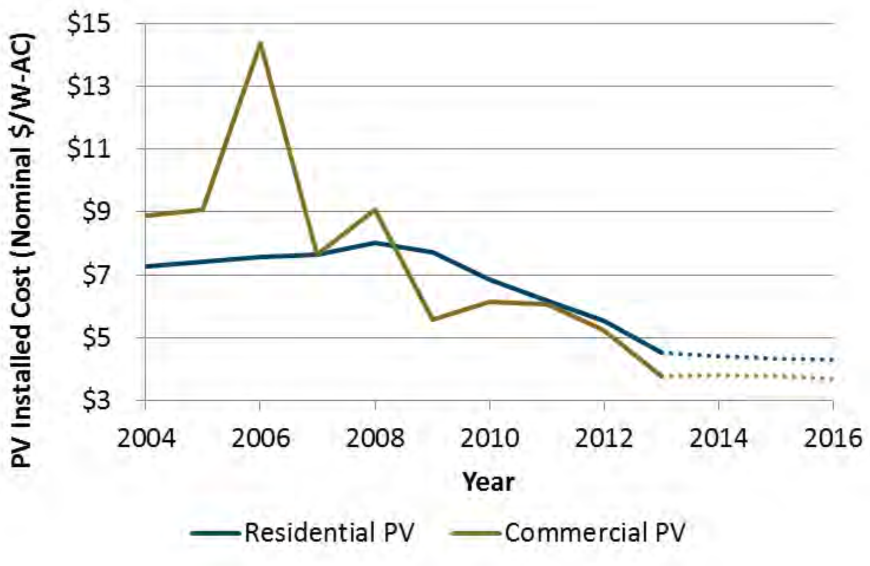
[20] Approximately 10% of systems had missing or clearly incorrect data.

interactive WECC-wide stakeholder process. More information on our capital cost projection methodology is available in our report to the WECC.[21]

Figure 15 shows the PV costs used in our analysis. The historical values represent the average costs reported in the RenewableGenerations installation database, which are volatile in the early years of the program when the total installed DG capacity was small. The projected prices from 2014 through 2016 show a leveling off of PV installed costs. These projections remain well-within U.S. Department of Energy forecasts.[22]

Figure 15: Historical and Forecast Rooftop PV Costs



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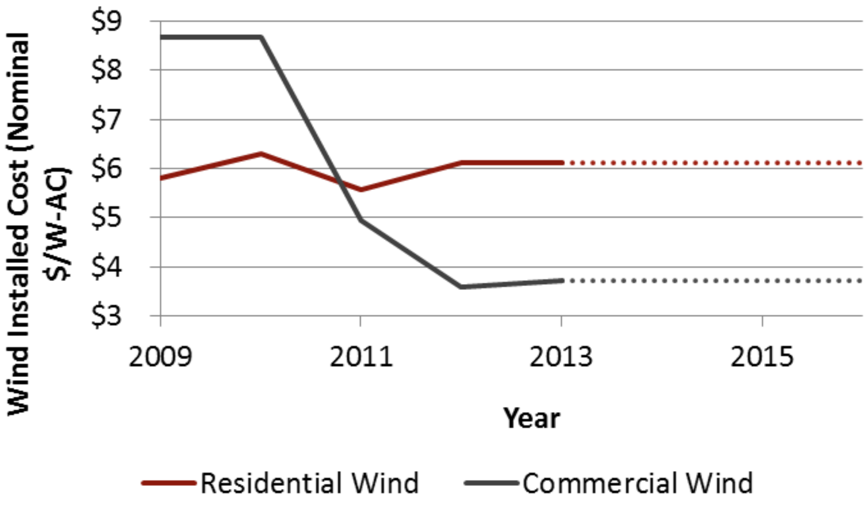
[21] E3's 2014 capital cost report and capital cost pro forma model are available for download on the WECC website: http://www.wecc.biz/committees/BOD/TEPPC/Pages/2015_Plans.aspx

[22] U.S. Department of Energy Sunshot Initiative: *PV Pricing Trends: Historical, Recent, and Near-Term Pricing Trends.* Available at: http://www.nrel.gov/docs/fy13osti/56776.pdf

3.10.1.2 Wind Cost Forecast

In general, less data is available regarding the cost of DG wind than the cost of rooftop solar. We developed a forecast of DG wind costs based on the Energy Information Agency (EIA) Annual Energy Outlook 2013.[23] EIA's forecast shows costs decreasing at approximately 2% per year in real terms beyond 2010. We applied the same rate of cost decrease to the RenewableGenerations average reported wind installation cost from 2013. Assuming an inflation rate of 2%, the result is that wind prices flatten out beyond 2013 in nominal terms. Figure 16 shows the annual DG wind installation costs used in our analysis.

Figure 16: Historical and Forecast DG Wind Costs



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[23] EIA's DG wind forecast is summarized at: http://www.eia.gov/analysis/studies/distribgen/system/

3.10.2 OPERATIONS AND MAINTENANCE COSTS

We approximated O&M costs from the NREL estimate of DG renewable energy costs.[24] We assume a fixed O&M cost of $20/kW-yr for all rooftop solar installations and $30/kW-yr for all DG wind installations (both in $2013).

3.10.3 FEDERAL TAX CREDITS

There are two predominant federal tax credits that renewable energy generators qualify for: the ITC and the production tax credit (PTC). Only the investment tax credit is available to solar installations, but both the ITC and PTC are available to wind installations. Small, customer-sited wind generators typically receive a larger tax benefit from the ITC, so we make the assumption that all NEM wind installations in Nevada opt for the ITC over the PTC. The ITC began in 2006 for customer-sited solar generators, and small wind generators became eligible for the credit in 2008. The credit value is 30% of eligible installed system capital costs through the end of 2016, when it drops to 10%. We assume that third party system owners are always able to fully access the ITC tax benefits.

3.10.4 UTILITY INCENTIVES

In addition to federal tax credits, NV Energy offers incentives to owners of new renewable DG through the RenewableGenerations program. Through the year 2013, NV Energy provided incentives upfront on a $/kW installed basis. NV Energy submitted a proposal to significantly modify the program in 2013, and

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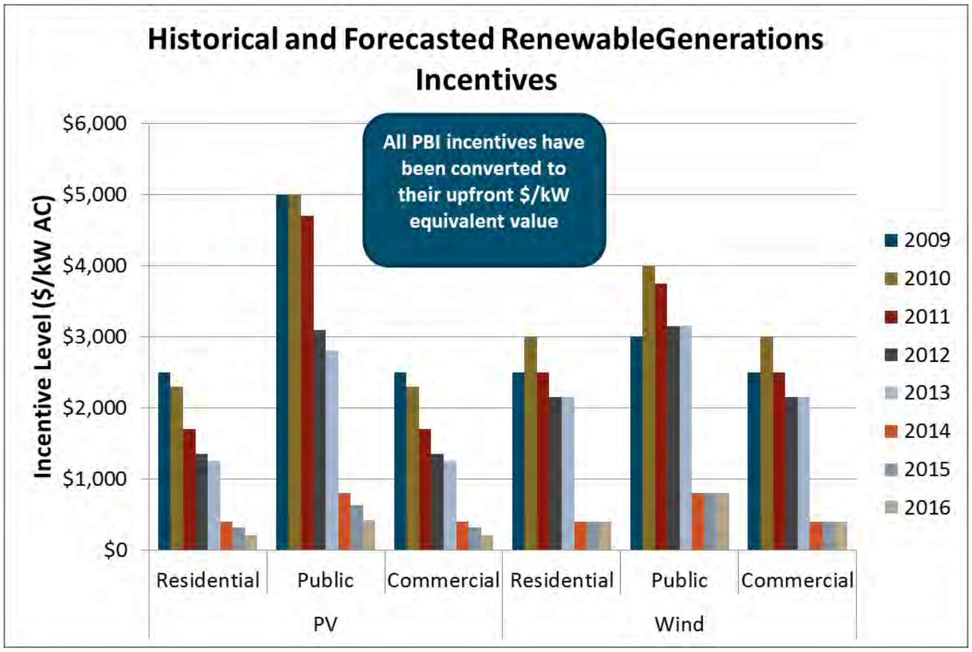
[24] NREL O&M cost estimates are available at: http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html

we assume this proposal will be accepted. The modification replaces the upfront incentives with PBIs for all wind systems and PV systems larger than 25 kW. The PBI incentive is paid for a period of 5 years. The PV upfront incentive and PBI are designed to be equal in total payouts, assuming a PV capacity factor of 21%. Figure 17 shows NV Energy's historical and projected incentive levels. Due to the declining capital cost of renewable DG, incentive levels have decreased over time. Future utility incentive levels (2014-2016) are a function of total installed NEM capacity. These incentive projections are consistent with the capacity install forecast (Section 3.2) and NV Energy incentive levels (Table 11).

Figure 17: Historical and Projected Utility Incentive Levels



Because we show aggregate results for all non-residential participants, we use a capacity-weighted average of the public and private incentive levels for non-residential installations. NV Energy provided information on the type of incentive received by each existing NEM system. We assume a 50-50 split between public and private non-residential systems going forward.

NEM participants can receive RenewablesGenerations incentives even if their systems are third-party owned. For example, a school can install a NEM PV system through a third party, and the project will receive both the public incentive level and the full ITC (the tax credit is absorbed by the third party).

4 Cost-Benefit Results

4.1 Results Framework

This section defines the metrics we use to present results for each of the five cost tests using Net Present Value (NPV) and levelized $/kWh costs and benefits by component. We then illustrate each cost test and its components through example graphs and explanations on the interpretation of these results. We recommend becoming familiar and comfortable with these examples before viewing the actual results in following sections.

4.1.1 KEY METRICS

We use two key metrics to present results: NPV and levelized $/kWh. The NPV metric is computed via the following steps:

1. Add up all of the benefits and costs for each year (in nominal $)
2. Subtract the costs from the benefits for each year to obtain the annual net benefit (in nominal $)
3. Using the appropriate discount rate, calculate the NPV of the full net benefit stream in 2014 dollars

Levelized $/kWh values are calculated for one cost or benefit component as follows:

1. Add up all of the costs or benefits to be analyzed by year (in nominal $)
2. Using the appropriate discount rate, calculate the NPV of the cost/benefit stream in 2014 dollars
3. Add up all of the NEM generation to be analyzed by year (in nominal kWh)
4. Using the appropriate discount rate, calculate the NPV of the generation stream in 2014 kWh
5. Divide the value obtained in step 2 by the one obtained in step 4

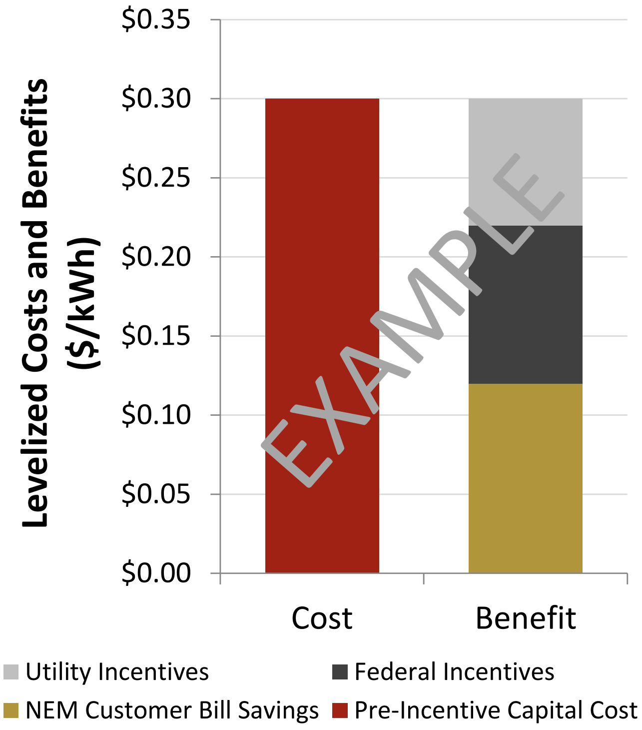
The NPV metric captures the total magnitude of the impact of NEM throughout the lifetimes of the analyzed NEM systems. This metric is largely driven by installed NEM capacity and generation, and it does not indicate how much of the overall benefit (or cost) is driven by program size versus cost-effectiveness of individual NEM systems. As a result, it is difficult to use this metric to understand how the impact of NEM may scale with additional NEM capacity and generation, or to compare the per-kW or per-kWh impacts across NEM vintage groups or other subgroups. It is an effective metric for capturing the total magnitude of the impacts.

The levelized $/kWh metric normalizes the NPV results for NEM generation. Consequently, this metric offers more insight into comparisons of costs and benefits across NEM vintage groups and other various subgroups. Unlike the NPV metric, it does not capture the aggregate NEM impacts or indicate the relative magnitudes of total net benefits across subgroups.

4.1.2 PARTICIPANT COST TEST (PCT)

The PCT analyzes the average customer's financial proposition when purchasing and installing a NEM system. Costs to the participant are simply the PPA costs paid to a third-party solar provider, shown in the charts as 'pre-incentive capital cost'. Benefits to the participant are reduced utility bills plus incentives received from NV Energy and the federal government that are passed on to the customer through the PPA price. Figure 18 shows an example of the levelized $/kWh costs and benefits.

Figure 18: Example PCT Levelized Results



In this example, the customer incurs a total cost of $0.30/kWh and a total benefit of $0.30/kWh. As portrayed in Figure 18, the total benefit is comprised of a $0.12/kWh bill reduction, a $0.10/kWh ITC, and an $0.08/kWh utility RenewableGenerations incentive. In this example, the net PCT benefit would be $0/kWh: the total benefits less the total costs. The total NPV would also be $0. All of these costs and benefits are in 2014 dollars.

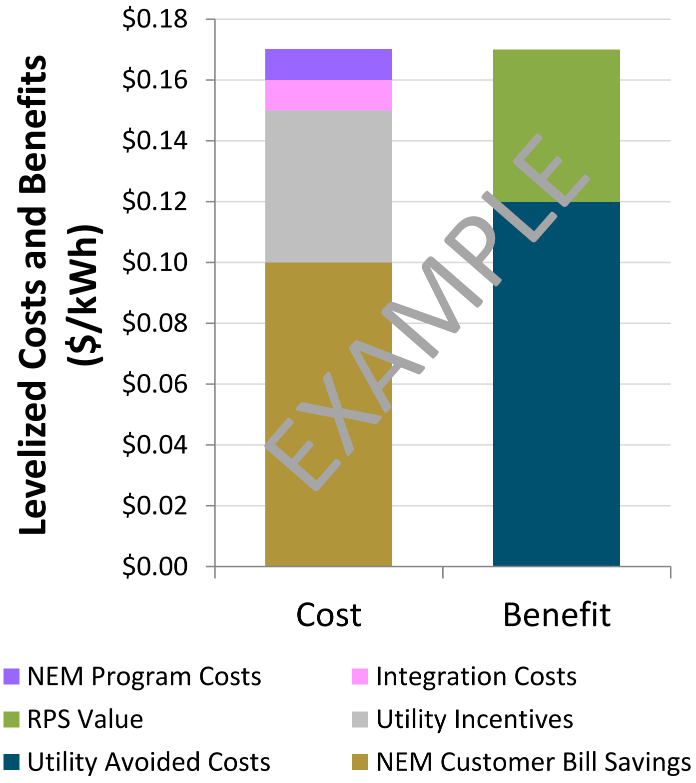
Comparing total costs to total benefits in the PCT test should be interpreted as follows:

	Benefits GREATER than Costs	Benefits LESS than Costs
Participant Cost Test (PCT)	The average NEM customer incurs a net economic benefit. The customer's electricity bill reduction is large enough to outweigh the PPA payments to a third-party provider.	The average NEM customer incurs a net economic cost. The customer's bill reduction combined with any incentives received does not outweigh the PPA costs.

4.1.3 RATEPAYER IMPACT MEASURE (RIM)

The RIM cost test measures the impact of NEM on NV Energy customers who are not participating in the NEM program. A net RIM cost means that average NV Energy electricity rates will increase, while a benefit indicates a reduction in average rates. Costs included in this test are costs to the utility of the NEM program, including: 1) lost utility revenue due to a reduction in NEM customers' utility bills, 2) the cost of paying utility incentives to NEM customers, and 3) NEM program and integration costs. The benefits are utility system costs that are avoided due to NEM generation. These avoided costs are outlined in Section 3.5 and include avoided energy, losses, system capacity, transmission capacity, ancillary services, and RPS compliance costs. One of the sensitivities also includes distribution avoided costs. Figure 19 shows the total levelized $/kWh costs and benefits flowing to non-participating ratepayers as a result of NEM.

Figure 19: Example RIM Levelized Results



In the above example, the total benefit to customers not participating in NEM is $0.17/kWh. Of this total, $0.05/kWh comes from the utility's avoidance of RPS compliance costs thanks to their ability to count NEM towards the Nevada RPS. The other $0.12/kWh benefit from NEM is the sum of all of the other avoided utility costs. The hypothetical costs to utilities and therefore non-participating customers are driven by the $0.10/kWh bill revenue reduction from NEM customers, and the $0.05/kWh RenewableGenerations rebate paid by utilities. The net levelized benefits in this example would be $0.17/kWh - $0.17/kWh = $0/kWh. The NPV would also be $0.

Comparing total costs to total benefits in the RIM test should be interpreted as follows:

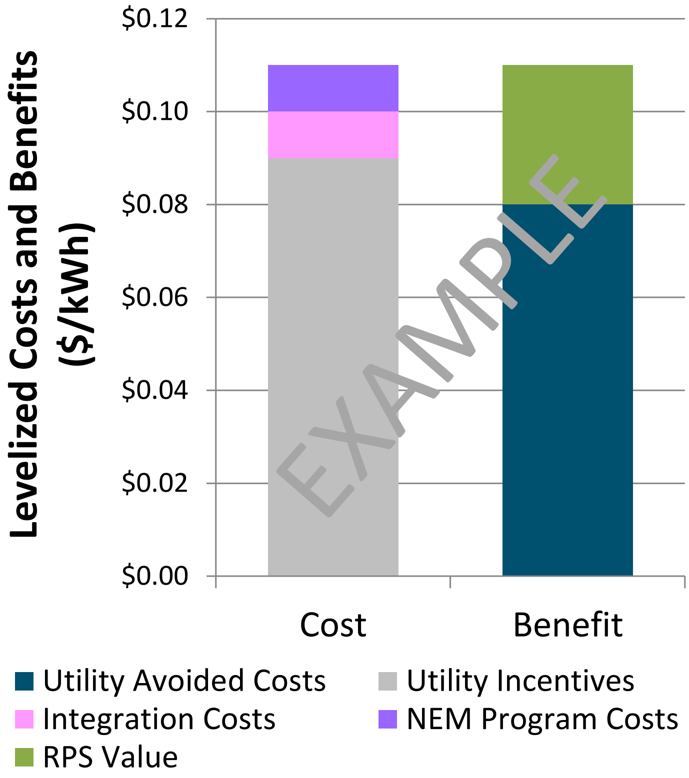
	Benefits GREATER than Costs	Benefits LESS than Costs
Ratepayer Impact Measure (RIM)	Average utility rates decrease for all utility customers. Non-participating customers benefit from the NEM program.	Average utility rates increase for all utility customers. Non-participating customers have to pay more as a result of the NEM program.

An increase in average utility rates is a cost-shift from NEM customers to non-participating utility customers.

4.1.4 PROGRAM ADMINISTRATOR COST TEST (PACT)

Also known as the Utility Cost Test (UCT), the PACT calculates the impact on NV Energy's revenue requirement, or the total bills paid to NV Energy. Costs and benefits are identical to the RIM test except that NEM customer bill savings are no longer included as a cost because they only represent a cost transfer between utility customers. Under this test, revenues not collected from NEM participants are not considered a cost to utilities because the revenues are collected instead from non-participants. Figure 20 portrays example PACT levelized $/kWh costs and benefits by component.

Figure 20: Example PACT Levelized Results



Comparing total costs to total benefits in the PACT should be interpreted as follows:

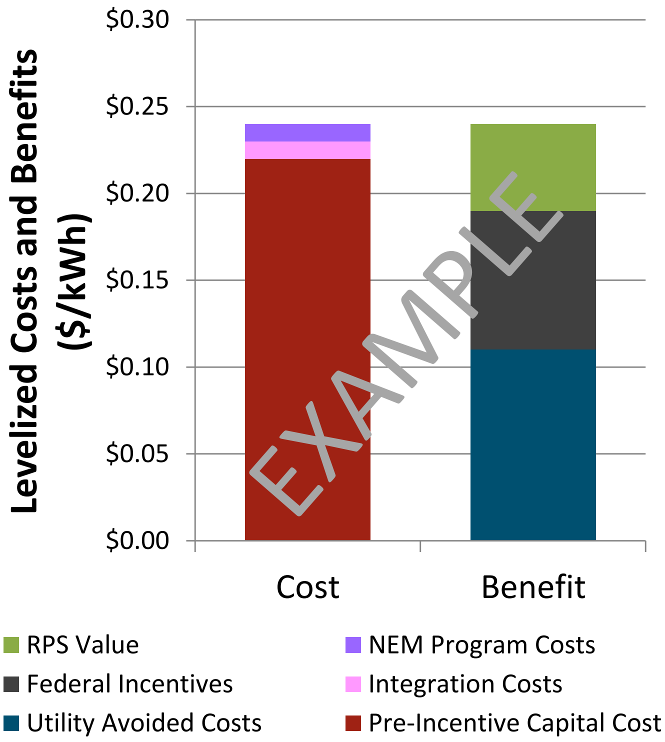
	Benefits GREATER than Costs	Benefits LESS than Costs
Program Administrator Cost Test (PACT)	Total utility bills and utility revenue requirement decreases as a consequence of NEM	Total utility bills and utility revenue requirement increases as a consequence of NEM

The NPV result represents the total increase or decrease in collected bills in 2014 dollars. A positive value means total bills paid is *reduced* while a negative value means total bills paid *increases.*

4.1.5 TOTAL RESOURCE COST TEST (TRC)

The TRC captures the total direct monetary impact of NEM on the state of Nevada. Under this test, the costs include NEM system capital costs as well as NEM program and integration costs. The benefits include the ITC for small solar and wind systems and utility avoided costs attributable to NEM, including RPS compliance avoided costs. In the example outlined in Figure 21, the state of Nevada incurs $0.24 in costs and receives $0.24 in benefits for every levelized kWh of NEM generation. The associated NPV would be $0.

Figure 21: Example TRC Levelized Results



Comparing total costs to total benefits in the TRC test should be interpreted as follows:

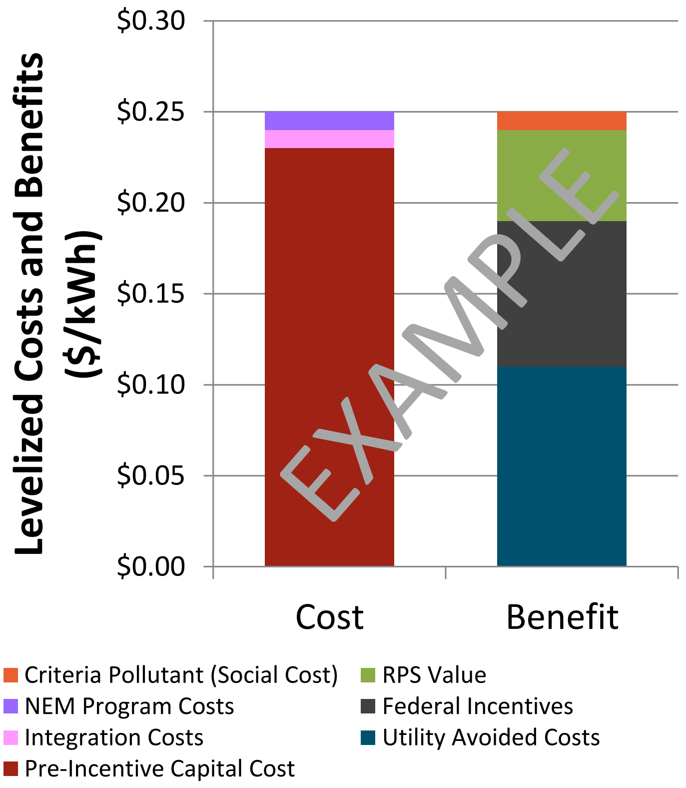
	Benefits GREATER than Costs	Benefits LESS than Costs
Total Resource Cost (TRC)	The state of Nevada receives a net economic benefit from NEM	The state of Nevada incurs a net economic cost from NEM

4.1.6 SOCIETAL COST TEST (SCT)

The SCT aims to quantify the total impact of NEM on the state of Nevada when externalities are included. All costs and benefits included in the TRC test outlined above are included in the SCT, and the SCT also adds a criteria pollutant reductions benefit. The other key difference between the TRC and the SCT is the discount rate used in the NPV and levelized $/kWh cost and benefit calculations. We do not estimate a social carbon cost, although monetized carbon costs are included in avoided energy costs.

Figure 22 displays example levelized $/kWh costs and benefits by component for the SCT.

Figure 22: Example NPV Benefit-Cost Summary Chart



Comparing total costs to total benefits in the SCT should be interpreted as follows:

	Benefits GREATER than Costs	Benefits LESS than Costs
Societal Cost Test (SCT)	NEM results in a net economic benefit to the state of Nevada when externality health benefits from criteria pollutant reductions are included	NEM results in a net economic cost to the state of Nevada INCLUDING when externality health benefits from criteria pollutant reductions are included

The NPV result represents the total lifetime net benefit (or cost) of NEM systems to the state of Nevada *including benefits of criteria pollutant reductions* in 2014 dollars.

4.2 Base Case Assumptions

We collaborated with the PUCN with input from the stakeholder advisory group to define a "base case" with a base set of input assumptions. Together, we chose assumptions based on plausibility and regulatory precedence. The base case assumes that the NEM tariff policy is in place, and the results reported compare this base case with the reference scenario of no NEM tariff policy (keeping all other Nevada policies as they exist). We also explore sensitivities by changing key, contentious inputs. Along with the general methodology assumptions described in Section 3, the following assumptions hold across all scenarios and sensitivities:

Table 17: Key Base Case Assumptions

Component	Value
Annual Inflation	2%
Utility After-Tax WACC (real) (Used to discount PCT, RIM, PACT, and TRC costs and benefits)	4.7%
Societal Discount Rate (real) (Used to discount SCT costs and benefits)	3%
Annual PV Panel Degradation Rate	0.5%
Annual Wind Turbine Degradation Rate	0.5%
PV/Wind System Lifetime	25 years
PV/Wind Economic Lifetime	25 years
Integration Cost ($2014/MWh)	$2/MWh
% of Future PV Installs Receiving Utility Incentives	90%
% of Future Wind Installs Receiving Utility Incentives	99%

Unless otherwise noted, the following assumptions hold in the **base case only**:

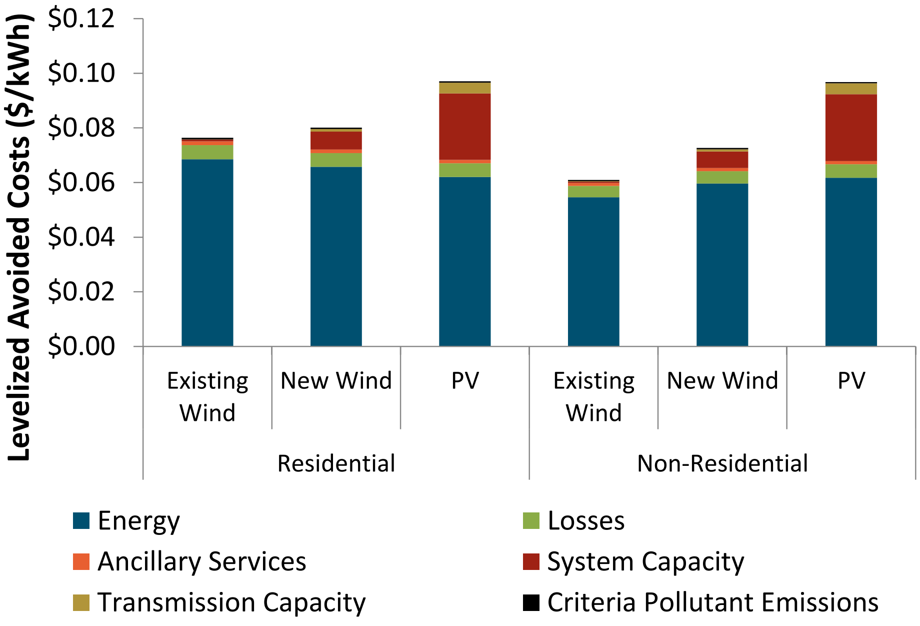
- NEM generation does not reliably avoid distribution upgrades
- Retail rates follow the structure of existing tariffs
- Retail rate escalation is derived from NV Energy's IRP through 2020 (the last year forecasted in the IRP) and then extended beyond 2020 based on the escalation of underlying marginal costs. The IRP projects real rate increases of 0.5% per year through 2020. After 2020, we use an annual real retail rate escalation of 1.4%. To calculate this value, we applied the fuel price projection from the IRP used in the avoided cost calculations to the energy portion of the retail rates. The value is a weighted average of the real escalation projected for natural gas prices (3.5%, applied to the energy portion of retail rates) and the 0.5% escalation rate (applied to the other portions of the retail rate).
- NEM generation does not reduce customer demand charges
- The avoided PPA price of utility scale PV is \$100/MWh (\$2014)

Section 1.2.3 provides results of sensitivities to a number of these base case assumptions.

4.3 Base Case Avoided Utility Costs

For each kWh generated by NEM systems, the utility avoids certain costs related to serving that load. For more detailed information on avoided costs, see Section 3.5. A breakdown of these avoided cost components by technology type and customer class is shown in Figure 23. The sum of these cost components are represented by "Utility Avoided Costs" throughout the results section. PV generally avoids more costs to the utility for each kWh generated due to its coincidence with utility load, allowing it to avoid more system capacity and higher cost energy and displace higher losses. Note that as previously mentioned, distribution capacity avoided costs are excluded in the base case and are not shown here. RPS avoided costs are also excluded from these charts although they are included in the base case analysis.

Figure 23: Base Case Levelized Avoided Cost Components by Technology and Customer Class



4.4 Base Case Results

4.4.1 RESULTS BY VINTAGE

Through 2013, over 60 MW of NEM capacity has been installed in Nevada, including 50 MW of PV and 10 MW of wind. Going forward, NV Energy projects an additional 230 MW of NEM capacity will be installed in 2014-2016. This section shows the costs and benefits for all systems installed through 2016 as well as results for three vintage groups: Existing systems installed through 2013, systems installed 2014-2015, and systems installed in 2016. Comparing the results across these vintage groups is important for understanding the impacts of the key policy changes outlined in Section 2.3.2. Figure 24 delineates the vintage groups and the key policy modifications and considerations for cost-effectiveness analysis.

Figure 24: Key Drivers of NEM Costs and Benefits by Vintage

All Vintages (2004-2016 NEM systems)

- Capital costs, the utility incentive program, treatment of public purpose charges , and the RPS policy vary across time

Existing Installations (through 2013)

- High NEM system pre-incentive capital costs
- High utility incentive levels, awarded using a lottery-based system

2014/2015 Installations

- Utility incentive program expanded and changed; Incentive levels reduced; upfront capital costs replaced with performance-based incentives for wind and large solar NEM systems; and incentives now offered on a first-come first-served basis
- Reduced capital costs
- Exports to the grid no longer receive bill credits for public purpose charges

2016 Installations

- RPS multiplier is eliminated for systems installed in or after 2016, decreasing the amount of utility-scale RPS capacity that NV Energy can avoid installing through each unit of NEM generation

4.4.1.1 Participant Cost Test (PCT)

We find that installing a NEM system was historically beneficial to the average customer participating in the NEM program, but given our forecast of installed PV costs this will no longer be the case for systems installed in 2014 through 2016. While NEM system capital costs have decreased over time, utility incentive reductions outweigh these capital cost reductions. Consequently, customers will have to be offered very competitive pricing for NEM generation systems in order for the state to meet NV Energy’s forecasted adoption levels.

As shown in Table 18, analysis of all systems installed through 2016 indicates that participants experience an NPV *cost* of $135 million and a levelized net cost of $0.02/kWh generated. As shown in Figure 25, levelized costs exceed levelized benefits by about $0.02/kWh when taken across *All Vintages*.

Figure 25: Participant Cost Test Levelized Results by Vintage

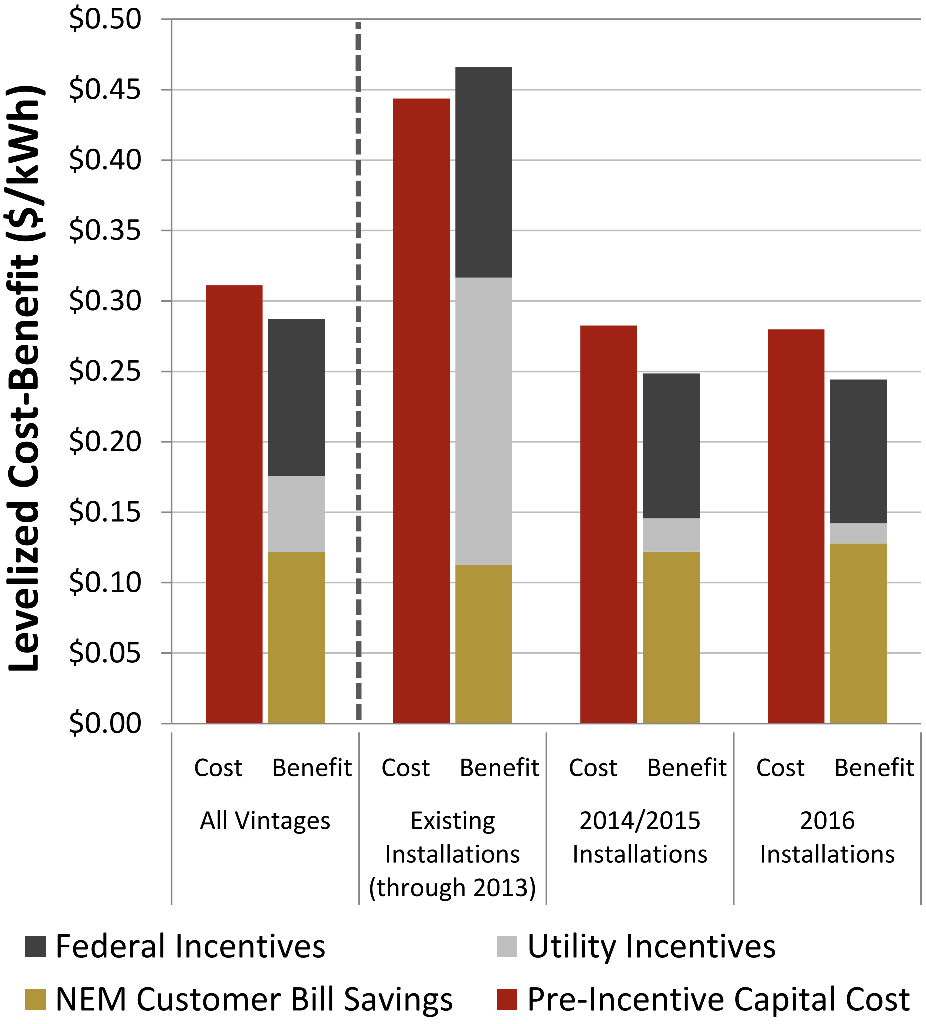


Table 18: Participant Cost Test NPV Results by Vintage

Benefit (cost) to customers who participate in NEM	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($Million 2014)	$23	($115)	($43)	($135)
Levelized ($2014/kWh)	$0.02	($0.03)	($0.04)	($0.02)

Historically, the levelized installed capital costs of distributed NEM systems were relatively high, about $0.44/kWh. However, utility incentives for purchasing those systems were also relatively high, about $0.20/kWh. Combined with the $0.15/kWh ITC and an approximate $0.11/kWh generated electricity bill reduction, this utility incentive caused the total participant benefits to exceed the capital costs by about $0.02/kWh prior to 2014. As shown in Table 18, the associated aggregate NPV *benefit* across all customers for systems installed prior to 2014 is $23 million.

In 2014, NV Energy and the PUCN reformed the RenewableGenerations program. The new program includes periodic utility incentive reductions tied to attainment of specific program penetration levels. As a result, the average levelized utility incentive is expected to drop to $0.024/kWh in 2014 and 2015 and to $0.014/kWh in 2016. As portrayed in Figure 25, this reduces the total levelized participant benefits to about $0.25/kWh. While capital costs are expected to drop to $0.28/kWh, this reduction is not large enough to outweigh the utility incentive reduction. Note that the reduction in the levelized ITC is partially due to reduced capital costs and partially due to increased wind capacity factors, which are explored in Section 3.10. We estimate that customers who install NEM systems in 2014-2016 will suffer a net NPV *cost* of $158 million across all customers, or $0.03/kWh, unless prices drop faster than our forecast.

The bill savings to participating customers are larger for forecasted NEM installations than for existing systems despite the public purpose charge bill credit exemption for exported energy reduced bill savings. This is primarily driven by the proportion of non-residential customers in each vintage group. Non-residential customers tend to have higher fixed charges and demand charges than residential customers, so they cannot avoid as much of their bill through net usage reductions. Historically, 78% of installed NEM capacity belonged to non-residential customers. Going forward, NV Energy predicts that 60% of installed NEM capacity will belong to non-residential customers.

Table 18 shows an NPV of -$115 million for systems installed in 2014/2015 and an NPV of -$43 million for systems installed in 2016. Note that these NPV results are largely driven by the higher installed capacity numbers in 2016. On a levelized $/kWh basis, the participant economics are roughly the same for all forecasted systems.

4.4.1.2 Ratepayer Impact Measure (RIM)

When analyzing all vintages (existing and forecasted) together, we estimate that NEM barely impacts non-participating customers. In fact, our base case estimate is that NEM reduces rates. Benefits are greater than costs in the *All Vintages* portion of Table 19 by approximately $0.006/kWh. Overall, the levelized avoided utility costs of NEM are $0.185/kWh, while the combined decreases in bills collected by utilities, utility incentives, program costs, and integration costs incurred are $0.179/kWh. The NPV results in Table 19 show that NEM systems of all vintages benefit all ratepayers by a total of $36 million. As explored in Section 4.5, the sign of this result is sensitive to a few key assumptions.

Figure 26: Ratepayer Impact Measure Levelized Results by Vintage

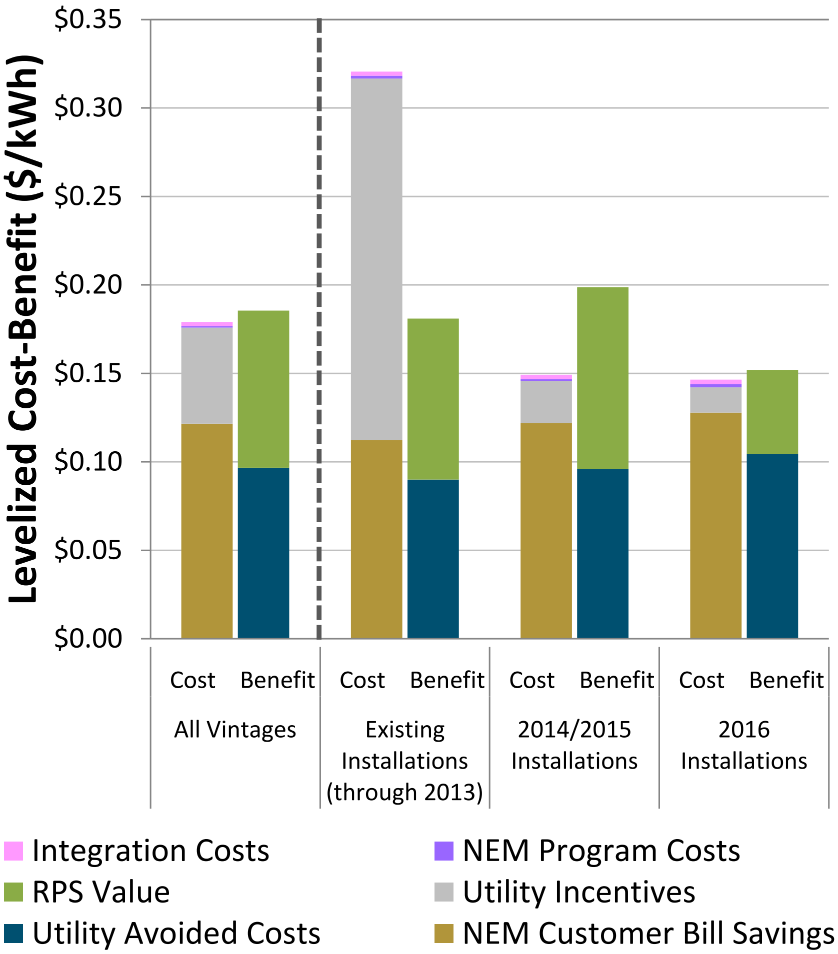


Table 19: Ratepayer Impact Measure NPV Results by Vintage

Benefit (cost) to non-participating ratepayers	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($Million 2014)	($141)	$168	$6	$36
Levelized ($2014/kWh)	($0.14)	$0.05	$0.01	$0.01

The results differ substantially across individual vintage groups. For systems installed in 2013 and prior, the utility offered large incentives to compensate for the large upfront capital costs faced by NEM customers. Correspondingly, ratepayers not participating in NEM experience a lifetime net NPV economic *cost* of $141 million or $0.14/kWh due to existing NEM systems. Thus, existing NEM installations have increased average utility rates and imparted a cost shift from participating customers onto non-participating ratepayers.

In 2014, NV Energy and the PUCN decreased utility incentives, which should actually reverse the cost shift created by existing NEM systems. The lifetime net economic *benefit* to ratepayers of NEM systems installed in 2014/2015 is $0.05 per kWh generated and $168 million overall.

RPS compliance value constitutes a large portion of the estimated 2014/2015 RIM benefits. In the absence of an RPS, NEM systems would be compared against thermal generators, and non-participating ratepayers would experience a net *cost* of about $0.06/ kWh generated. Because Nevada's RPS policy allows RenewableGeneration-incentivized NEM generation to count towards the RPS and allows unlimited banking of allowances, all such NEM generation can offset utility-scale RPS compliance investments *at some point*. As a result, this RIM test measures the non-participant impact of participants installing DG NEM systems *when customers choose to do so* against utilities building renewables *when they are needed* for RPS compliance. The temporal component of this comparison impacts the RPS compliance value of 2014/2015 systems substantially because of the RPS multiplier expiration.

In 2016, the NEM RPS multiplier is set to expire under Nevada law for new installations only. Prior to this expiration, for every MWh generated by a utility-incentivized NEM PV system, NV Energy gained 2.45 allowances to use towards RPS compliance. From 2016 onward, generation from NEM systems installed prior to 2016 will still receive this multiplier, but generation from new, incentivized NEM installations will receive RPS allowances on a one-for-one basis. Utility-scale PV built after 2016 will also offset RPS requirements on a one-for-one basis. Note that all NEM generation also provides additional RPS compliance value by decreasing the compliance obligation through net load reductions.

Given the base case assumptions, NV Energy has enough banked allowances and renewable procurement to avoid an RPS shortfall until 2020. NEM systems installed in 2014 and 2015 show such a large net benefit under the RIM test essentially because they are more effective at meeting the 2020 RPS shortfall than utility-scale renewables built around 2020. Again, this is driven by the RPS multiplier and the policy of unlimited banking of RPS allowances.

NEM systems installed in 2016 do not receive an RPS multiplier, so the levelized RPS compliance value decreases from $0.10 in 2014/2015 to $0.05 in 2016. These RPS values are the heights of the green RPS Value cost component bars in Figure 26 for the applicable vintage groups. However, even with this reduction, 2016 NEM systems still provide a small net economic *benefit* to non-participating ratepayers of $0.01/kWh and an aggregate NPV of $6 million.

4.4.1.3 Program Administrator Cost Test (PACT)

The PACT measures NV Energy's revenue requirement reduction and the corresponding, equivalent aggregate bill reduction across NV Energy customers. The PACT includes all of the same cost components as the RIM with the exception of NEM participant customer bill savings. NEM customer bill savings that exceed the avoided utility costs, if there are any, from NEM are collected by increasing the bills of other customers, so they have no impact on NV Energy's total bill revenue. The PACT measures the utility system costs that are avoided by NEM generation against the NEM program costs, integration costs, and incentive payments.

Figure 27 shows that NEM systems, when aggregated across all vintages, create a reduction in total customer bills in aggregate. We estimate the total avoided utility costs, including RPS compliance value, to be approximately $0.18/kWh, while the incentive, program, and integration costs are estimated to be only $0.06/kWh. Taken together, NEM systems are associated with an aggregate NPV of $716 million.

Figure 27: Program Administrator Cost Test Levelized Results by Vintage

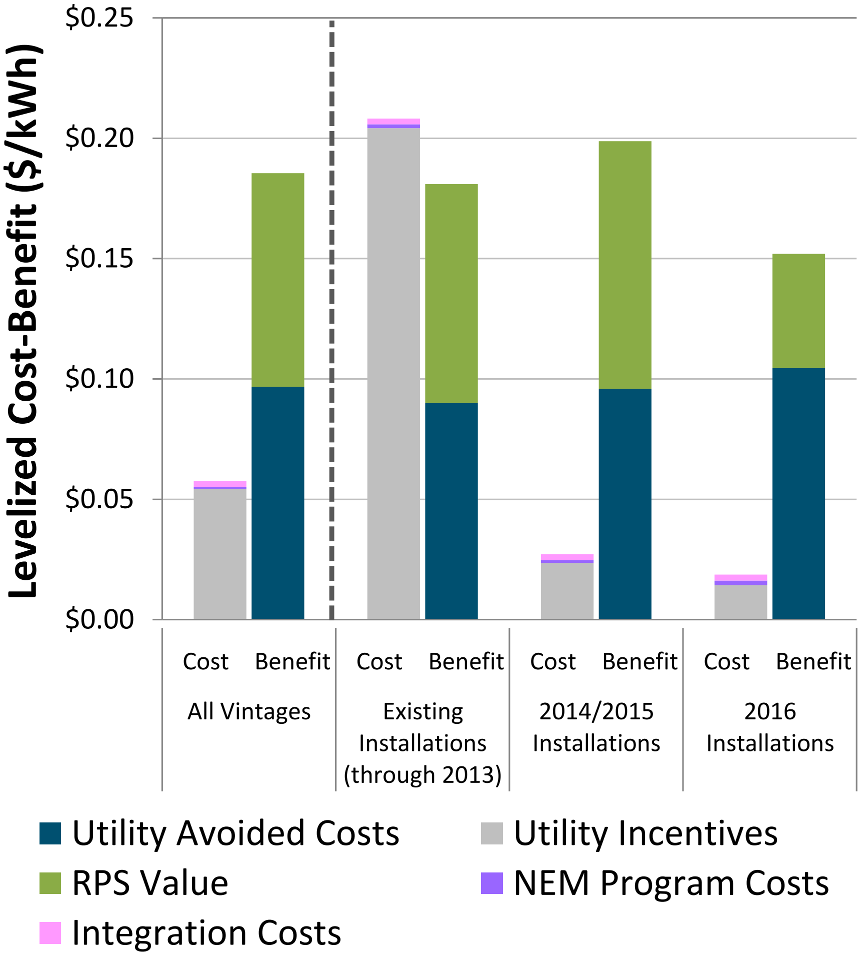


Table 20: Program Administrator Cost Test NPV Results by Vintage

Reduction (increase) in aggregate customer bills	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($Million 2014)	($28)	$581	$160	$716
Levelized ($2014/kWh)	($0.03)	$0.17	$0.13	$0.13

Historically, NEM systems actually increased NV Energy's revenue requirement and total customer bills because the utility incentives were larger than the avoided utility costs. The NPV bill revenue increase of existing systems is $28 million or $0.03/kWh.

In 2014 through 2016, the utility incentive levels will decrease substantially. NEM generation still provides many utility system benefits, but NV Energy only needs to recover a small portion of the NEM system capital costs and minimal program and integration costs through its rate base. Table 20 summarizes the NPV of total utility customer bill savings due to NEM. Once again, note that a positive value represents a reduction in customer bills while a negative value represents an increase.

4.4.1.4 Total Resource Cost Test (TRC)

The TRC shows that overall, the state of Nevada incurs a NPV economic *cost* of about $100 million, or $0.02/kWh, from all NEM systems installed through

2016. As shown in Figure 28, the NEM system capital costs exceed the utility avoided costs even with the assistance of the ITC.

Figure 28: Total Resource Cost Test Levelized Results by Vintage

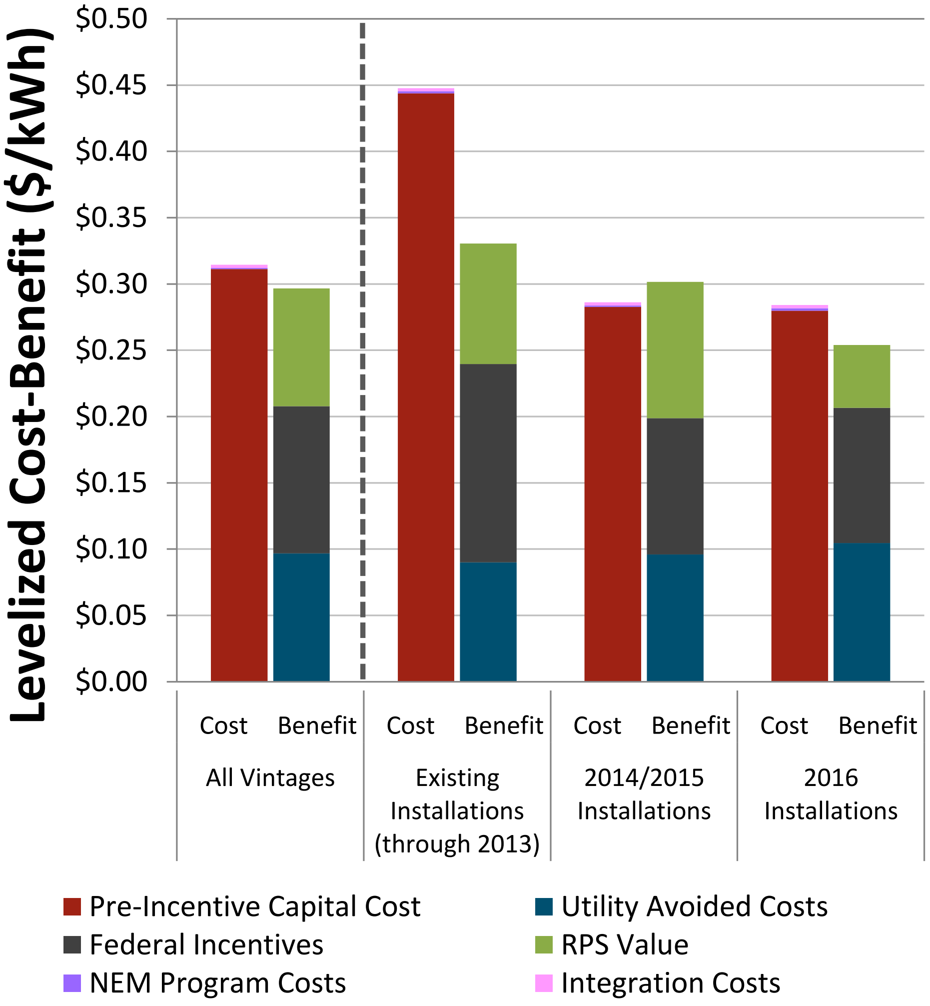


Table 21: Total Resource Cost Test NPV Results by Vintage

Benefit (cost) to the state of Nevada	Installs through 2013 Lifecycle NPV $MM	Installs in 2014-2015 Lifecycle NPV $MM	Installs in 2016 Lifecycle NPV $MM	All installs through 2016 Lifecycle NPV $MM
Lifecycle NPV ($MM 2014)	($119)	$52	($36)	($100)
Levelized ($2014/kWh)	($0.12)	$0.02	($0.03)	($0.02)

Existing NEM systems (installed through 2013) show an even larger economic *cost* to the state of Nevada. As indicated in Table 21, we estimate that existing systems create an economic NPV cost over the course of the NEM system lifetimes of $119 million. The associated levelized cost is $0.12/kWh generated. This large cost is driven by the high historical NEM system capital costs. These capital costs far exceed the utility avoided costs, even including the large RPS compliance cost that the utility avoids through NEM. As discussed previously, a number of aspects of the RPS policy, including the multiplier on DG PV, drive this large RPS compliance value and, therefore, the net overall cost.

On the other hand, forecasted systems to be installed in 2014/2015 show an economic *benefit* to the state of Nevada of NPV $52 million or $0.02/kWh. This result is driven by a large reduction in capital costs and an RPS value that is still large because 2014/2015 NEM systems continue to receive the 2.45 RPS multiplier during this time period.

When the RPS multiplier expires in 2016, that benefit component correspondingly decreases and the net result once again shows an economic *cost* to the state of NEM systems in 2016. We estimate the cost to be NPV $36 million or $0.03/kWh of NEM generation.

4.4.1.5 Societal Cost Test (SCT)

The SCT calculations are identical to those used in the TRC above, except that the SCT employs a lower discount rate and includes the additional monetized impact of criteria pollutant reductions.

The lower discount rate slightly reduces the overall NPV cost to the state of Nevada. Relative to the TRC, the SCT deemphasizes the net costs in the early years and increases the emphasis on the small net benefits in the later years. The impact of a discount rate change is small primarily because the PPA financing assumed for all NEM owners already spreads the capital costs over many years, and benefits and costs are therefore already occurring during similar time periods. The discount rate barely impacts levelized values, although it does increase the difference between levelized costs and benefits. This is because a lower discount rate increases the magnitudes of the benefit NPVs, the cost NPVs, *and* the generation NPVs.

We find that the overall health impacts of NEM are very small and negative. Because of Nevada's RPS and the multiplier on NEM generation, the installation of NEM systems avoids and defers utility-sited renewable development. The timing of NEM installations relative to the reference case utility-sited renewable development combined with the PV RPS multiplier and unlimited banking of RPS credits, causes NEM to avoid utility-sited generation on a basis greater than one-to-one.

Because customers install NEM systems when it is in their own economic interest, NEM capacity is installed before NV Energy would otherwise need to build utility-scale renewables for RPS compliance. This results in a net emissions reduction in the early years of the analysis. However, renewable generation from NEM PV systems installed prior to 2016 receive the 2.45 RPS multiplier. They also further assist RPS compliance by reducing net load, the basis for the compliance obligation calculation. Consequently, installing 1 MW of NEM PV capacity prior to 2016 will displace about 2.7 MW of future utility-sited renewable generation. This will result in less renewable generation and more emissions overall, resulting in fewer health benefits.

When the RPS multiplier is eliminated for 2016-vintage NEM systems, we find a negligible net health impact. NEM generation replaces utility-sited generation roughly on a one-to-one basis. NEM reduces emissions by 1) causing installation of renewables before they are required for RPS compliance and 2) by encouraging installations of non-incentivized renewable DG systems that do not produce RPS allowances. However, this is completely offset by the fact that NEM reduces the RPS compliance obligation, a function of net load, in addition to producing RPS allowances that can be used for compliance. Unlike NEM generation, utility-sited generation does not impact the compliance obligation itself.

As shown in Figure 29, the levelized results of the SCT are very similar to those of the TRC. Table 22 shows the NPV results by vintage. The differences in the values of Table 21 and Table 22 are driven by the discount rates.

Figure 29: Societal Cost Test Levelized Results by Vintage

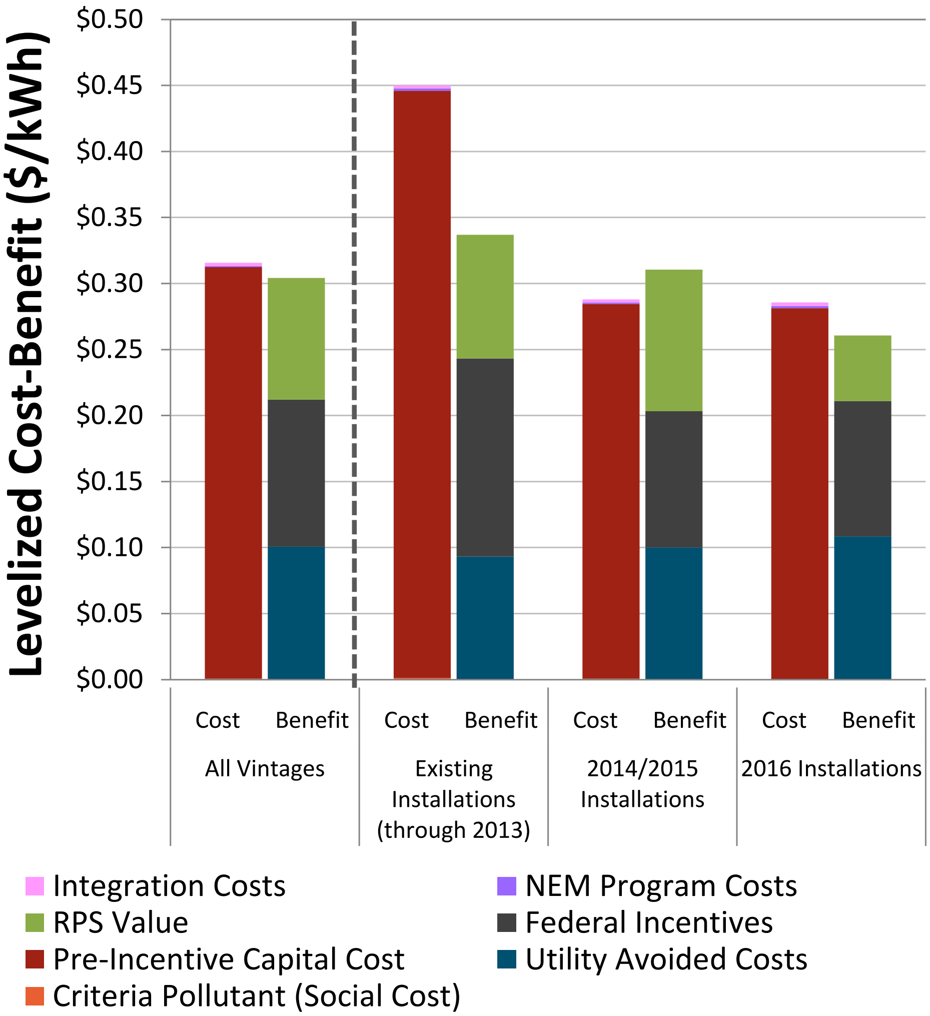


Table 22: Societal Cost Test NPV Results by Vintage

Benefit (cost) to the state of Nevada, including externalities	Installs through 2013	Installs in 2014-2015	Installs in 2016	All installs through 2016
Lifecycle NPV ($Million 2014)	($133)	$90	($36)	($75)
Levelized ($2014/kWh)	($0.11)	$0.02	($0.02)	($0.01)

4.4.2 RESULTS BY TECHNOLOGY

This section separately analyzes the impacts of each NEM technology: PV (installations through 2016), existing wind (installations through 2013), and forecasted wind (2014-2016 installations). Wind is disaggregated into existing wind and forecasted wind because the NEM policy rules for wind changed substantially in 2014. NV Energy expects the policy change to substantially improve performance characteristics of new NEM wind systems.

In 2014, NV Energy and the PUCN adopted a new rule that all NEM wind generators must be installed in locations where the average wind speed is at least 10 mph. Prior to this requirement, nearly all NEM wind was installed in areas with drastically lower wind speeds. As a result, existing NEM wind capacity produces at an extremely low average capacity factor (~2%). Going forward, the new requirements should cause forecasted NEM wind systems to produce at much higher capacity factors, estimated at approximately 17%. We analyze existing wind and new, ‘forecasted wind’ separately to better understand the impact of increased capacity factors due to the incentive program change. We do not differentiate existing and forecasted PV as NV Energy does not expect the performance characteristics to change substantially in 2014.

We present the results for the PCT, RIM, and TRC cost tests. We do not present the results of the PACT or SCT because we believe the results of the other tests sufficiently capture the key differences across technologies.

4.4.2.1 Participant Cost Test (PCT)

The most striking result of the PCT results show in Figure 30 is the very high levelized costs and benefits of existing wind. This is explained almost entirely by the extremely low average capacity factor of existing wind. Pre-incentive capital costs, federal incentives, and utility incentives are all fixed $/kW values, and the NPV of each of these cost components are not affected by the capacity factor of the NEM system. However, the results in Figure 30 are the cost or benefit NPVs divided by the NPV of generation. When the systems produce very little energy, this denominator is very small, causing large levelized values. Note that the only benefit component that *is* dependent upon energy generation, NEM customer bill savings, does not increase proportionally to the other costs and benefits. This is because the denominator (generation) decreases proportionally to the numerator (total bill savings).

We estimate the levelized participant cost of existing wind to be $0.27/kWh, but the net aggregate NPV cost is only $7 million due to low penetration levels of NEM-participant wind. Under the new RenewableGenerations wind speed requirements, the levelized participant cost decreases to $0.09, and the aggregate NPV cost decreases to $0.2 million. Participants with high-performing wind systems have much larger bill savings than customers with wind systems facing low wind speeds.

Even with the adjustments to the wind RenewableGenerations requirements, NEM wind is less economic from a participant perspective than NEM PV. This discrepancy is primarily driven by difference in capacity factors. The average PV capacity factor is around 21%, and the average forecasted wind capacity factor is only about 17%. Consequently, the average NEM wind owner will experience lower electricity bill reductions than the average NEM PV owner. NEM wind owners will also receive lower utility PBI payments.

Figure 30: Participant Cost Test Levelized Results by Technology

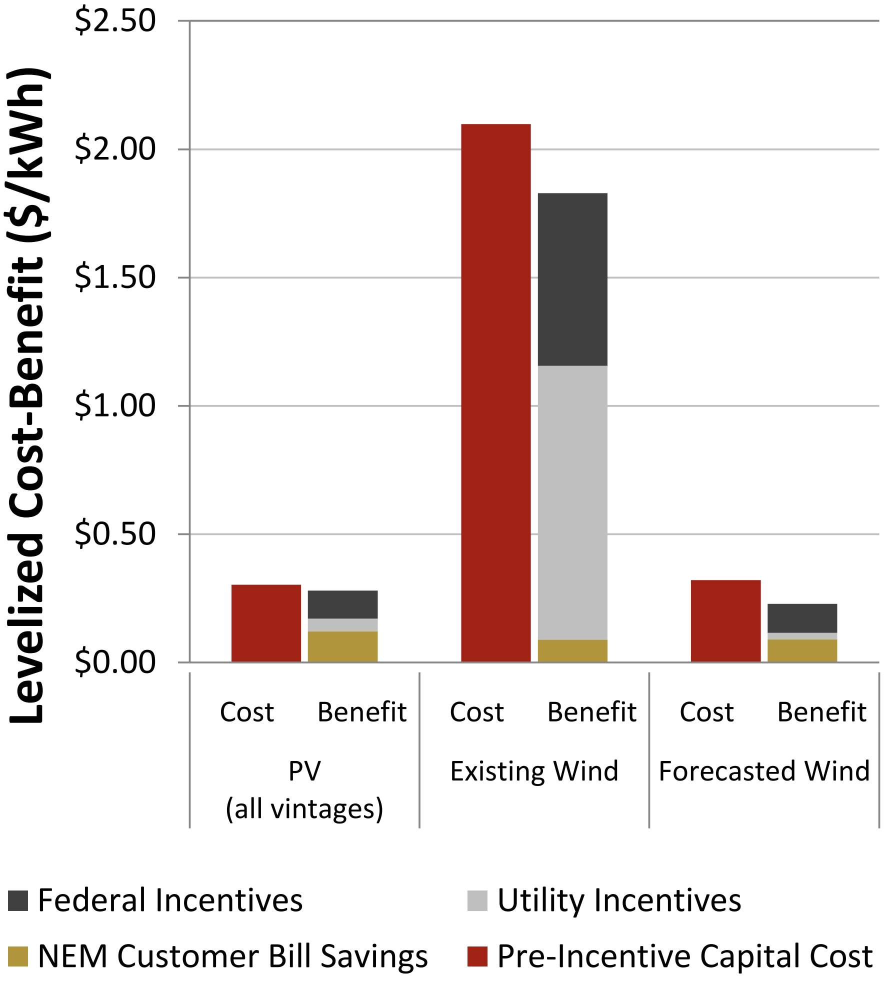


Table 23: Participant Cost Test NPV Results by Technology

Benefit (cost) to customers who participate in NEM	PV	Existing Wind	Forecasted Wind
Lifecycle NPV ($Million 2014)	($128)	($7)	($0.2)
Levelized ($2014/kWh)	($0.02)	($0.27)	($0.09)

The relatively small total NPV result for wind shown in Table 23 reflects the small wind installation forecast. The large total cost to PV customers of $128 million is due to a substantial forecast of over 250 MW of installed PV by 2016.

4.4.2.2 Ratepayer Impact Measure (RIM)

The RIM results show that NEM PV systems provide a small benefit to non-participating ratepayers by decreasing average rates. The total NPV economic benefit to ratepayers due to these PV systems is $64 million, or $0.01/kWh. As discussed in section 4.5.5, the sign of this result is very dependent on assumptions about future utility-scale solar costs that are inherently unknown.

As with the PCT, the extremely low average capacity factor of existing wind systems cause a very negative RIM result for existing wind. We estimate the levelized net cost shift of existing wind to be $1.06/kWh. Due to small levels of penetration, the aggregate NPV cost shift is only $28 million. While the low capacity factor of existing wind limits NEM customers’ bill savings, it also limits the utility system benefits and limits the avoided utility costs. As shown in

Figure 31, it is the utility incentive that dominates the RIM results. Since the utility incentive was historically based on installed capacity without regards to performance, we estimate the average levelized utility incentive has been $1.07/kWh.

With the improved capacity factors for forecasted wind systems, the reduced utility incentive levels, and the shift from upfront incentives to PBI incentives from 2014 forward, the cost shift from participating to non-participating wind customers will be essentially eliminated. We estimate that the NPV cost of forecasted NEM wind systems to non-participating ratepayers will be less than $0.01/kWh or $5,000 total. This result is so close to zero and there is enough inherent uncertainty in the input assumptions that we cannot be certain about the sign of this result.

Forecasted NEM wind is less beneficial to non-participating ratepayers than NEM PV primarily due to the lower capacity factor of wind versus PV and the fact that the 2.45 RPS multiplier only applies to DG PV. NEM wind systems cannot create as much avoided utility system cost as the PV NEM systems due to wind systems' lower average capacity factor. Incentivized NEM PV also provides about twice as much RPS value as NEM wind because 1 MWh of incentivized NEM PV installed through 2015 is awarded 2.45 kPCs for RPS compliance, while 1 MWh of incentivized NEM wind is only awarded 1 kPC. PV is also typically more effective at reducing net load due to higher capacity factors. As shown in Figure 31, the levelized RPS value of NEM PV is $0.09/kWh, while the RPS value is only $0.04/kWh for forecasted NEM wind.

Figure 31: Ratepayer Impact Measure Levelized Results by Technology

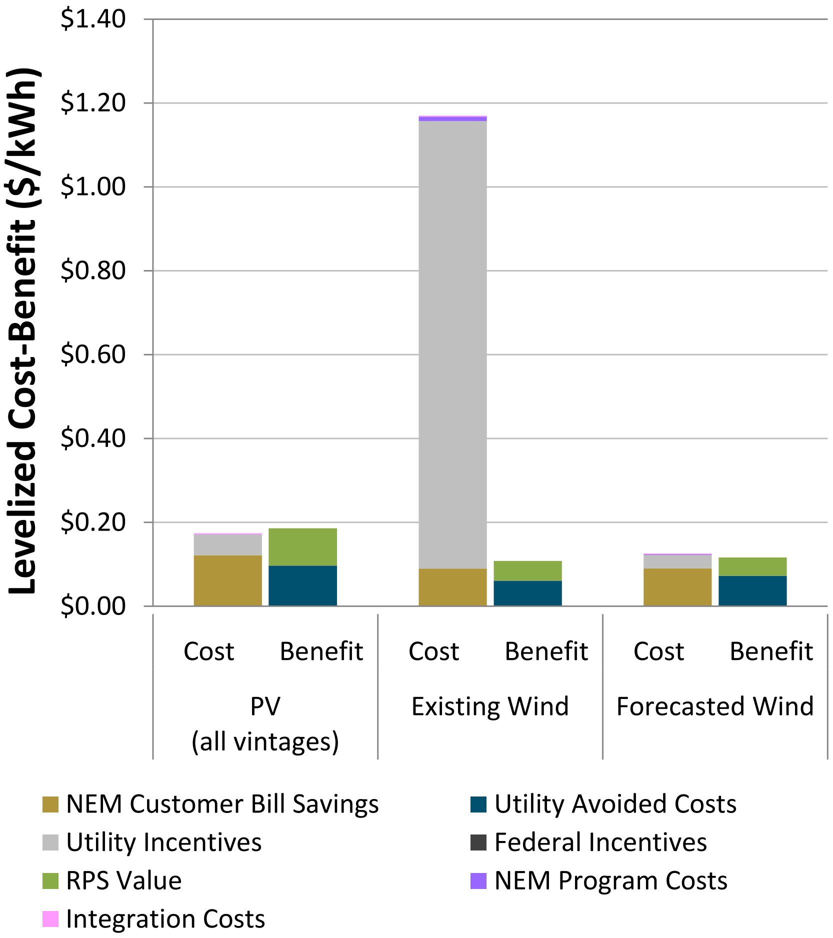


Table 24: Ratepayer Impact Measure NPV Results by Technology

Benefit (cost) to non-participating ratepayers	PV	Existing Wind	Forecasted Wind
Lifecycle NPV ($Million 2014)	$64	($28)	($0.02)
Levelized ($2014/kWh)	$0.01	($1.06)	($0.01)

4.4.2.3 Total Resource Cost Test (TRC)

Comparing PV costs and benefits in Figure 32 shows that the state of Nevada incurs a very slight net levelized cost of $0.01 per kWh produced by PV NEM systems. Section 4.5.5 demonstrates that the sign of this result is sensitive to key assumptions.

As with the other cost tests, NEM wind is much more uneconomic than NEM PV when analyzed on a levelized basis. For both existing and forecasted wind systems, total costs to the state of Nevada exceed benefits by a significant margin. We estimate the net cost to be $1.33/kWh for existing wind and $0.10/kWh for forecasted wind. Once again, the levelized cost differences between existing wind, forecasted wind, and PV are driven by capacity factors and the RPS DG PV multiplier.

On an aggregate NPV basis, PV systems result in a net economic cost of $64 million to the state of Nevada, while existing wind systems result in a net economic cost of $35 million. The higher PV NPV cost is entirely driven by the higher NEM PV historical and forecasted installed capacity relative to NEM wind.

Figure 32: Total Resource Cost Test Levelized Results by Technology

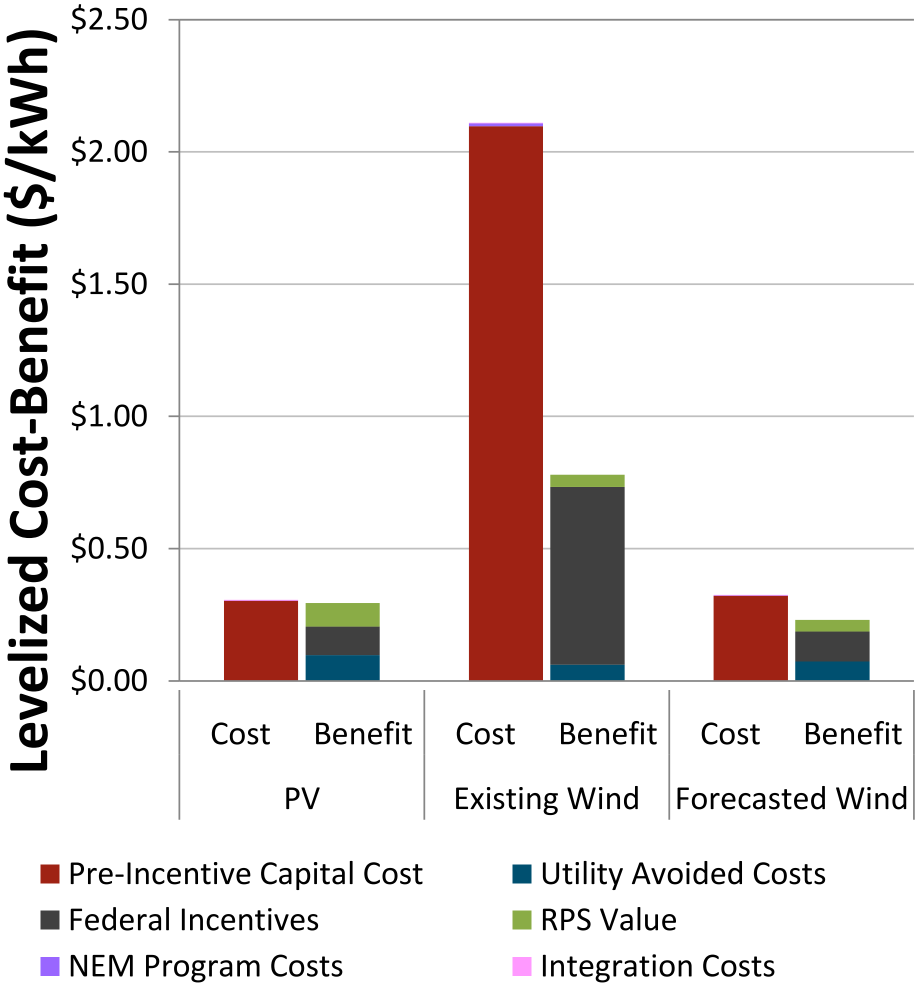


Table 25: Total Resource Cost Test NPV Results by Technology

Benefit (cost) to the State of Nevada	PV	Existing Wind	Forecasted Wind
Lifecycle NPV ($Million 2014)	($64)	($35)	($0.2)
Levelized ($2014/kWh)	($0.01)	($1.33)	($0.10)

4.4.3 RESULTS BY UTILITY INCENTIVE STATUS

In an effort to promote renewable energy and meet certain statewide policy goals, NV Energy offers financial incentives to customers who purchase and install qualifying NEM generators. The cost of these incentives is ultimately borne by ratepayers, as NV Energy is entitled to recover these costs through rates. However, NV Energy (and thus ratepayers) also incurs benefits specifically tied to these incentive payments, namely the claim to the renewable energy credits of the NEM systems that can be used to offset utility-sited RPS obligations. Along with the statutory RPS multiplier, this produces a significant financial benefit to ratepayers by reducing obligatory renewable energy purchases and construction.

This section compares the cost-effectiveness of incentivized and non-incentivized NEM systems under the PCT, RIM, and TRC cost tests. We exclude the PACT and SCT results from this section because we do not think they add any information not reflected in the RIM and TRC results.

4.4.3.1 Participant Cost Test (PCT)

The results of the PCT show clearly that participants benefit from receiving utility incentives. However, with or without a utility incentive, participants still experience an aggregate net cost of installing NEM systems, as shown in Table 26. Historical incentivized systems received a levelized net benefit of about \$0.06/kWh, but the average participant with a forecasted incentivized NEM system or a non-incentivized NEM system of any vintage incurs a net cost.

In aggregate, NEM customers who receive utility incentives experience a net levelized cost of \$0.02/kWh generated, while non-incentivized NEM customers experience a levelized cost of \$0.07/kWh. This difference is almost entirely driven by the \$0.06/kWh levelized utility incentive, although other characteristics of incentivized vs. non-incentivized system installations, such as installation years and residential proportion, also impact the results.

The NPV results are shown in Table 26. Note that the total cost to participants with incentivized systems is greater than for non-incentivized systems even though the levelized results show an opposite conclusion. Once again, this is because there are many more incentivized than non-incentivized systems.

Figure 33: Participant Cost Test Levelized Results by Utility Incentive Status

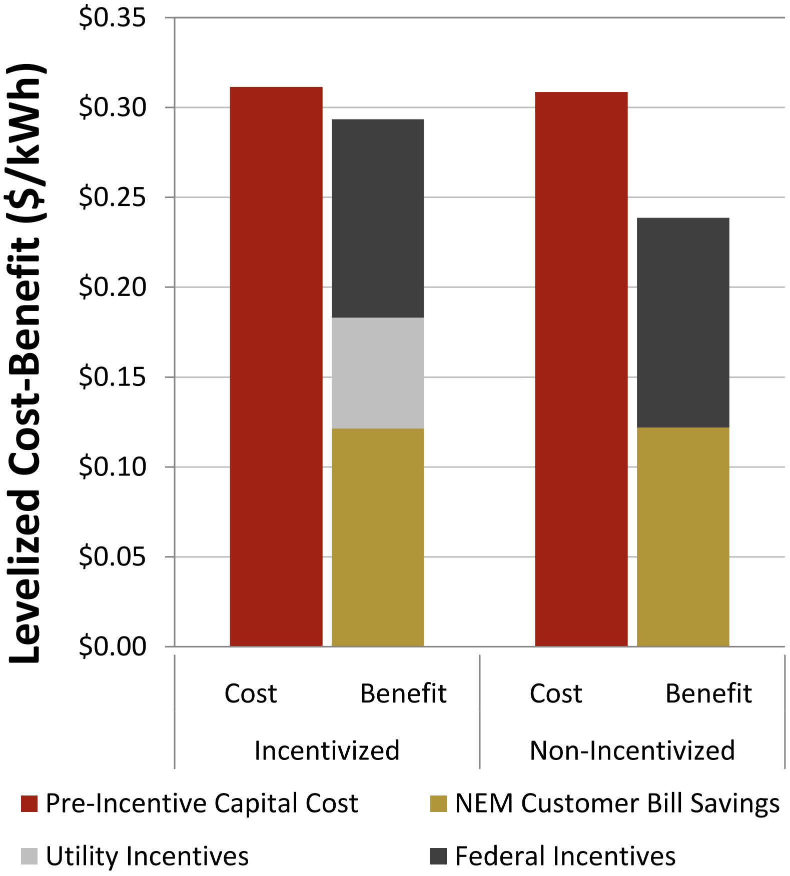


Table 26: Participant Cost Test NPV Results by Utility Incentive Status

Benefit (cost) to customers who participate in NEM	Incentivized	Non-Incentivized
Lifecycle NPV ($Million 2014)	($89)	($47)
Levelized ($2014/kWh)	($0.02)	($0.07)

4.4.3.2 Ratepayer Impact Measure (RIM)

Using the base case assumptions, we estimate that NEM systems that receive utility incentives decrease average utility rates, while non-incentivized NEM systems increase average utility rates. This result is somewhat surprising given the fact that offering an incentive is an additional cost the utility that is ultimately borne by the ratepayers. However, the larger RPS compliance benefit of incentivized systems (particularly with the RPS multiplier) is more than enough to offset the cost of the incentive. Therefore, incentivized NEM systems are more beneficial to non-participating customers than non-incentivized systems.

Under the RIM cost test, incentivized NEM systems provide an estimated net benefit of $0.01/kWh, compared to an estimated net cost of $0.02/kWh for non-incentivized systems. As shown in Figure 34, the overall levelized utility incentive is $0.06/kWh, but this benefit is more than offset for incentivized systems by a $0.09/kWh reduction in RPS value. The total RPS value for incentivized systems is $0.10/kWh, while non-incentivized systems only provide an RPS value of $0.01/kWh. Non-incentivized systems only provide RPS value by reducing net load.

Figure 34: Ratepayer Impact Measure Levelized Results by Utility Incentive Status

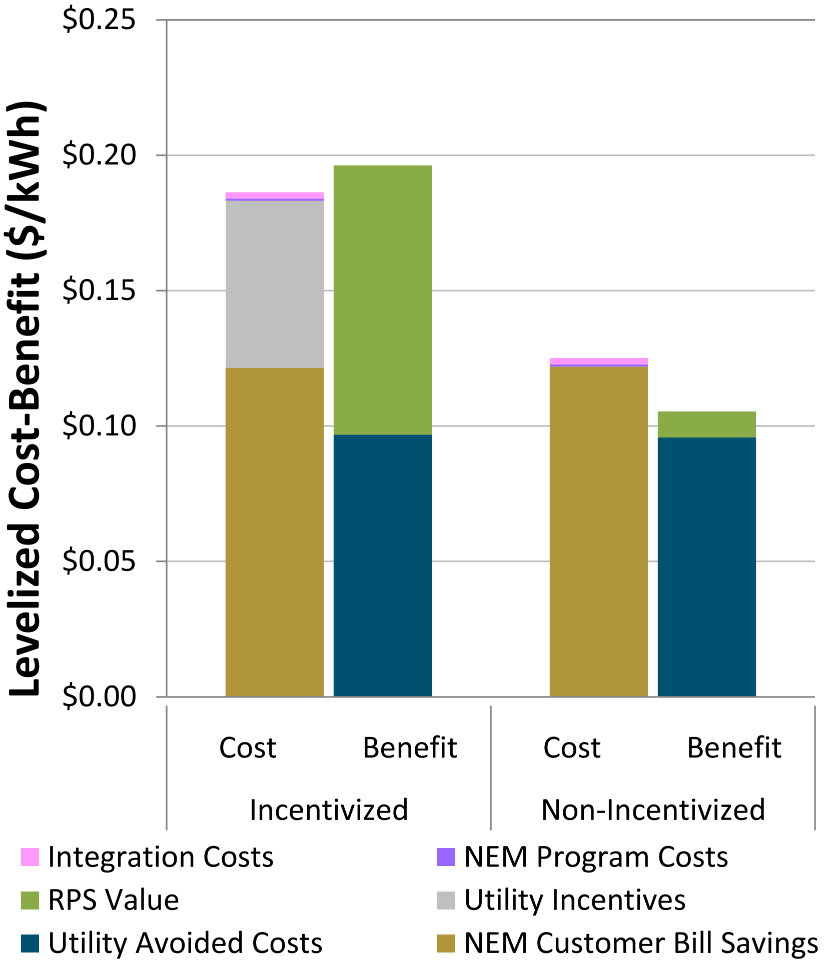


Table 27: Ratepayer Impact Measure NPV Results by Utility Incentive Status

Benefit (cost) to non-participating ratepayers	Incentivized	Non-Incentivized
Lifecycle NPV ($Million 2014)	$49	($13)
Levelized ($2014/kWh)	$0.01	($0.02)

4.4.3.3 Total Resource Cost Test (TRC)

Incentivized NEM systems are preferable to non-incentivized systems from the perspective of the state of Nevada. Because utility incentive payments are transfers between parties within Nevada, there is no statewide cost of incentivizing NEM systems. RPS eligibility of incentivized systems does, however benefit the state by deferring building utility-scale renewables or avoiding purchasing renewable energy from other states. The levelized TRC cost of non-incentivized NEM is about $0.09/kWh, while the TRC cost of incentivized NEM is only $0.01/kWh.

In aggregate, non-incentivized NEM is more costly to the state of Nevada than incentivized NEM despite the fact that more NEM systems are incentivized. We estimate the NPV costs to the state as $60 million for non-incentivized NEM and $40 million for incentivized NEM.

Figure 35: Total Resource Cost Levelized Results by Utility Incentive Status

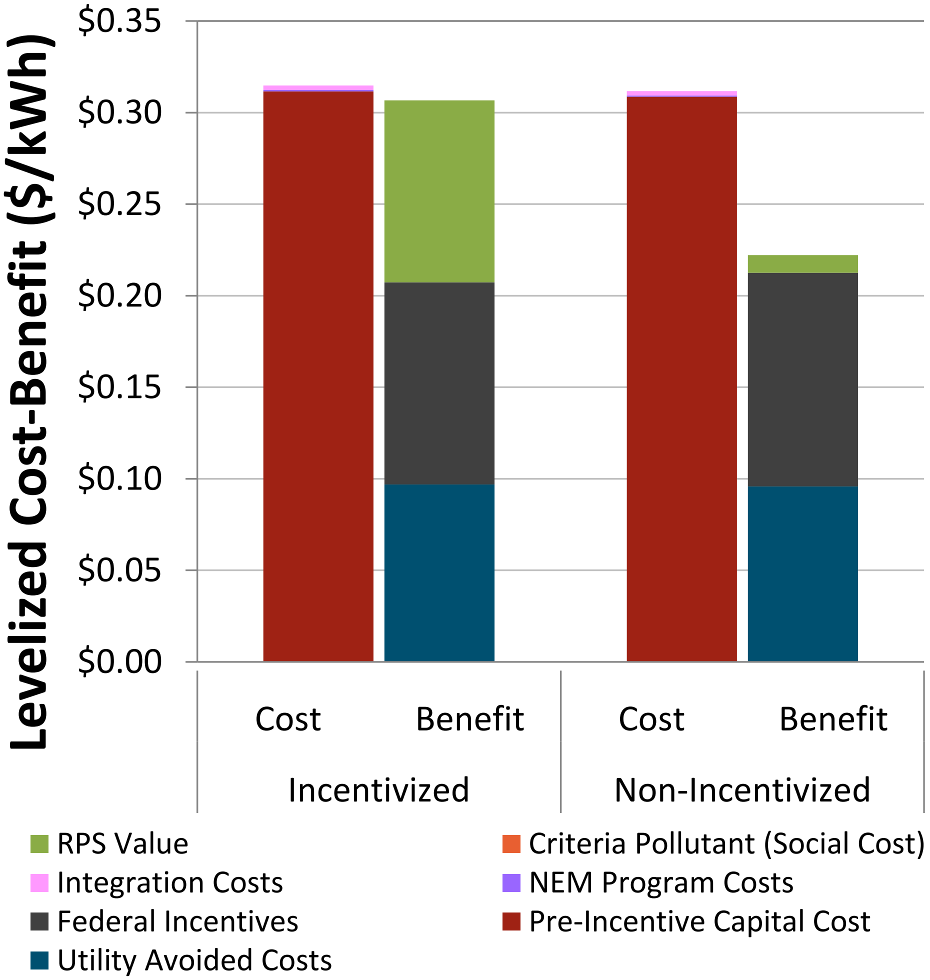


Table 28: Total Resource Cost NPV Results by Utility Incentive Status

Benefit (cost) to non-participating ratepayers	Incentivized	Non-Incentivized
Lifecycle NPV ($Million 2014)	($40)	($60)
Levelized ($2014/kWh)	($0.01)	($0.09)

4.5 Sensitivity Results

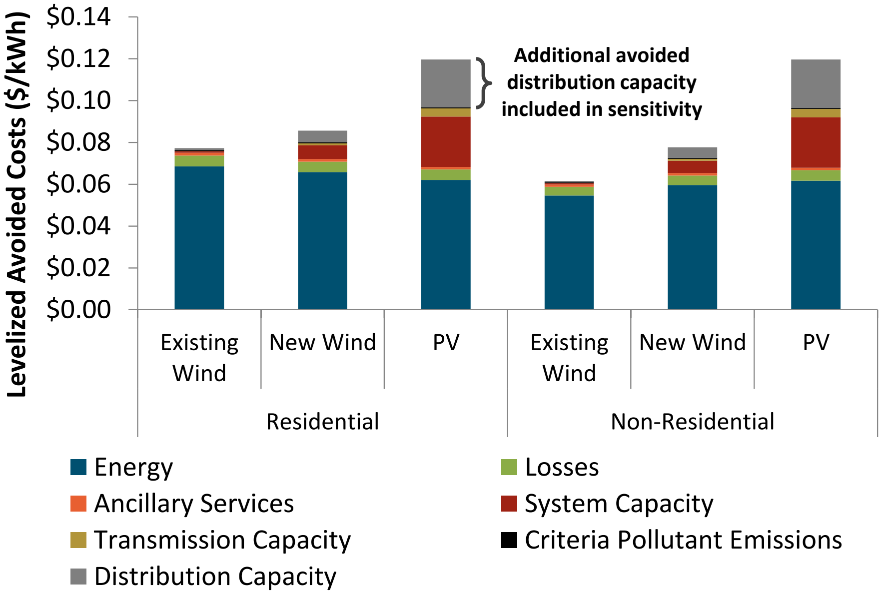
Under the direction of the PUCN, we developed sensitivities to the base case to show how key assumptions and inputs might affect final results. All sensitivity results include NEM installations of all vintages (existing and forecasted) and use base case inputs for all assumptions except those explicitly mentioned.

4.5.1 DISTRIBUTION AVOIDED COSTS SENSITIVITY

The base case assumes that NEM generation cannot avoid distribution system upgrades, due to the intermittency of renewable generation. Intermittency is especially problematic when considered in the context of a single distribution circuit, without the aggregation that occurs when DG installations are considered over a larger geographic area. This sensitivity evaluates how much utility avoided costs would increase if distribution capacity upgrades could be reliably avoided by NEM generation. We award the full value of avoided distribution upgrades to NEM generation in this scenario, representing an upper bound of distribution benefits.

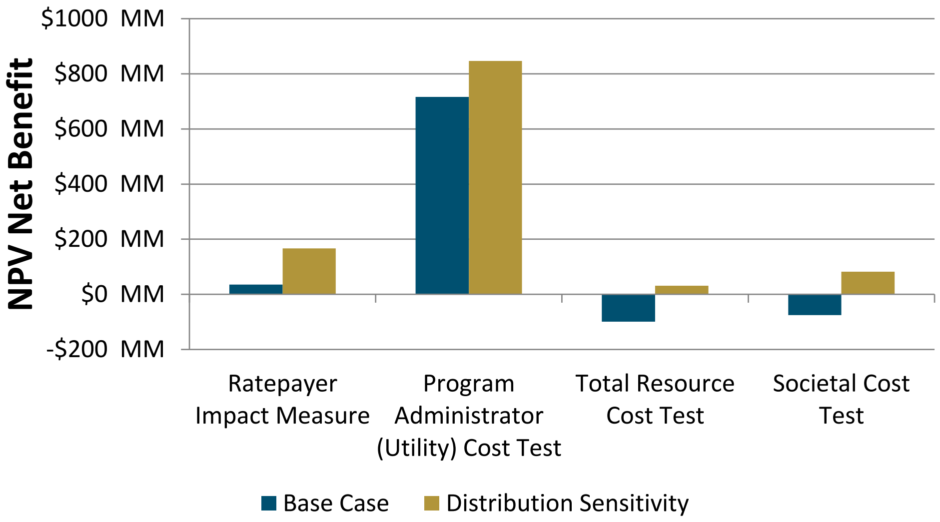
Only the cost tests that include the utility avoided cost component are affected by this sensitivity: RIM, PACT, TRC, and SCT. Figure 36 shows the avoided costs by component with the addition of distribution capacity. This chart is identical to the base case avoided costs breakdown (Figure 23) with the addition of the gray distribution capacity component at the top of each column. As with transmission and system capacity upgrades, distribution capacity upgrades are most frequently avoided by PV generation as opposed to wind due to coincidence with load.

Figure 36: Avoided Cost Breakdown, Distribution Sensitivity



These avoided distribution upgrades increase benefits by a total of $130 MM. Figure 37 shows how the NPV (aggregate costs minus benefits) in each affected cost test changes with the inclusion of the distribution benefit. The distribution benefit is large enough to change the results of the total resource cost test and societal cost test from a net cost to a net benefit.

Figure 37: NPV Net Benefits, Distribution Sensitivity

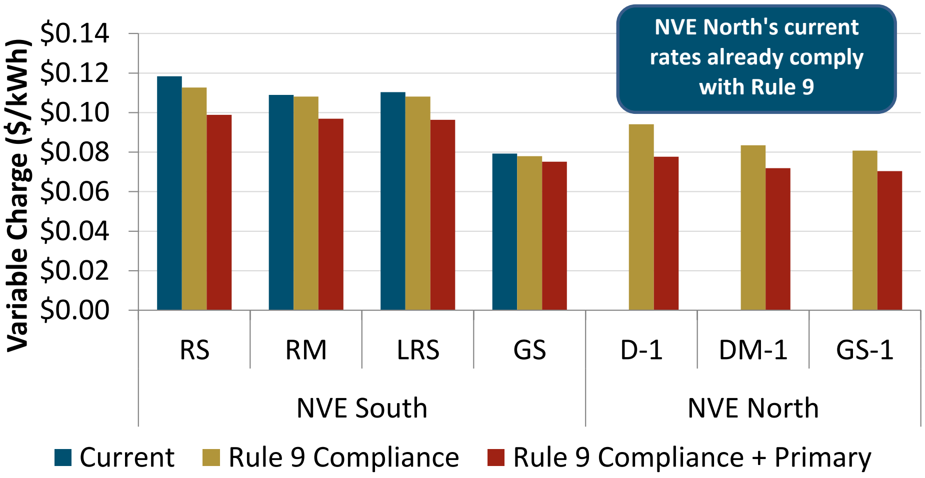


4.5.2 RATE SCENARIO SENSITIVITIES

Rate structure plays a large role in the overall cost impact to both participants and non-participant ratepayers. NV Energy recovers its revenue requirement through a combination of fixed and variable charges. NEM generation can only reduce variable charges. If rate designs changed to recover more of the revenue requirement through fixed charges, the variable portion of the rate would decrease, thereby reducing the bill savings of NEM customers. A decrease in NEM customer bill savings necessarily leads to a decrease in net benefits in the PCT and an increase in net benefits in the RIM. It is important to note that the NEM installation forecast does not change with this rate scenario sensitivity even though different rate structures might make NEM more (less) appealing to potential participants and thus increase (decrease) forecasted installations.

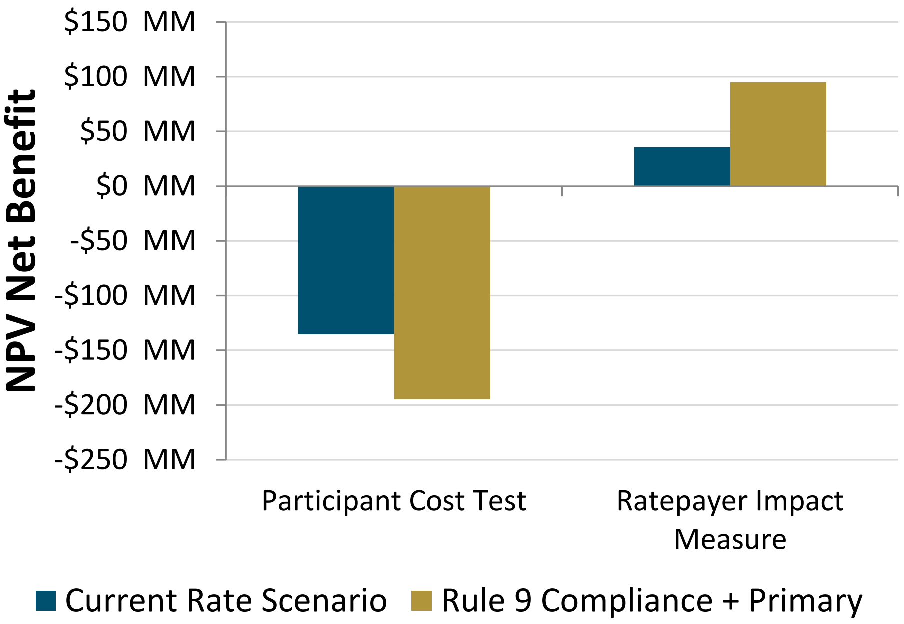
The base case evaluates costs and benefits using the current rate structure for both utilities. NVE South and NVE North have developed two plausible sets of alternative future rates, designed to recover a higher portion of utility costs through fixed charges. In the first scenario, NVE South’s rates are modified to be compliant with the new Rule 9, which shifts some distribution cost recovery into fixed charges. NVE North’s rates are already Rule 9 compliant, as of their 2013 general rate case (GRC). NVE South’s most recent GRC was completed in 2011; the forthcoming GRC will include an update to Rule 9 compliance. In the second scenario, both utilities’ rates are adjusted to include the primary distribution revenue requirement in the fixed charge. We performed this sensitivity for the most common rates for each utility. Figure 38 shows how the variable rates decrease as fixed charges increase for major rate categories within NVE South and NVE North.

Figure 38: Utility Rate Scenarios



In general, these levels of variable rate changes do not substantially impact results, although they do increase the aggregate benefit to ratepayers by $12 million in the Rule 9 Compliance case and $59 million in the Rule 9 Compliance + Primary case. Figure 39 shows the change to NPV net benefit in the PCT and RIM between current rates and the case with the highest fixed charge.

Figure 39: NPV Net Benefits, Rate Scenario Sensitivity



4.5.3 RATE ESCALATION SENSITIVITIES

In addition to retail rate design, the escalation of retail rates has the potential to significantly impact future bill savings of NEM customers. The RIM is particularly sensitive to the retail rate escalation relative to the avoided cost escalation because it compares the relative magnitudes of these two components.

NV Energy’s 2013 IRP does not forecast real rate escalations past 2020 due to the inherent uncertainty in projecting rates far into the future. However, utility avoided cost estimates do escalate beyond 2020 in real dollars, primarily driven by the IRP’s natural gas forecast (which extends through 2043).

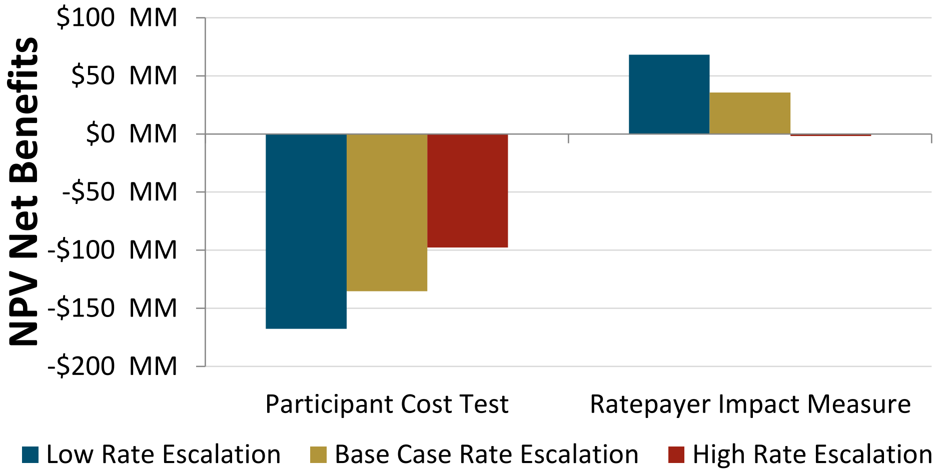
The base case increases rates annually at 0.5% real per year through 2020, as stated in the utility IRP, and then escalates at 1.4% real per year through 2041. The 1.4% estimate represents a weighted average of the energy portion of electric rates escalating at the natural gas forecast rate of 3.5%/year and all other rate components continuing to escalate at 0.5% real. We developed high and low escalation scenarios, outlined in Table 29, to demonstrate the impact of different retail rate escalations.

Table 29: Retail Rate Escalation Scenarios

Low retail rate escalation scenario	0.5% (2014-2041)
Base case retail rate escalation scenario	0.5% (2014-2020) 1.4% (2021-2041)
High retail rate escalation scenario	1.4% (2014-2041)

As rate escalation increases, benefits to the NEM customer increase and benefits to the ratepayer decrease. While NEM participants still experience a net economic cost under all rate escalation scenarios, a high retail rate escalation scenario would actually lead to net non-participating ratepayer costs.

Figure 40: NPV Net Benefit, Retail Rate Escalation Sensitivity



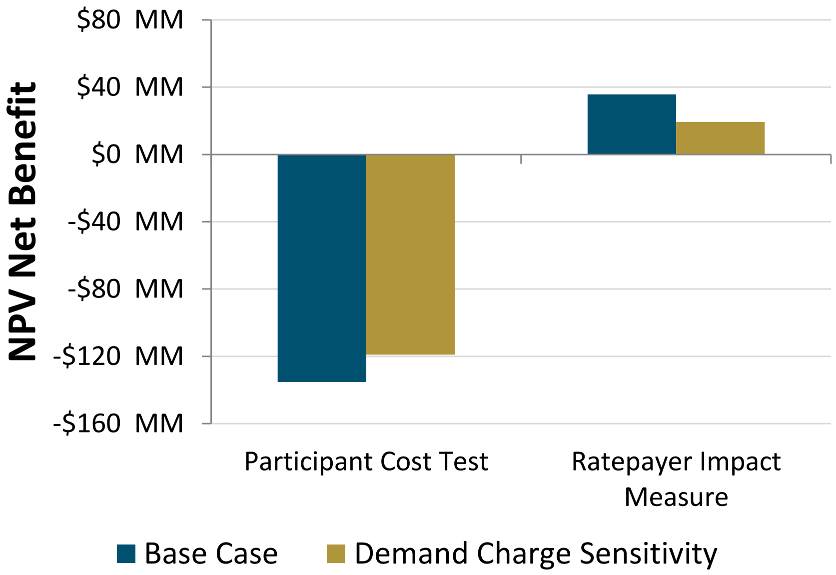
4.5.4 DEMAND CHARGE SENSITIVITY

Some of NV Energy's non-residential tariffs include a demand charge as a portion of bills. Demand charges are calculated by multiplying a fixed $/kW charge by the customer's peak load during a specific time period, typically the billing period. Throughout the base case, we assume that NEM generation does not reduce customers' peak demands, so we assume no demand charge savings. The bill savings we calculate online include savings in the variable cost portion of customers' bill. In reality, NEM generation presents the potential to reduce demand charges if production from the NEM system is coincident with the customer's peak load.

Because necessary data was not available to accurately calculate this, we decided collectively with the PUCN that this sensitivity would *reduce demand in* *all hours by 10% of the NEM system nameplate capacity*, which we believe to be a reasonable upper bound given the many confounding factors that affect this calculation.

Inclusion of a demand charge does increase participant net benefits and decrease ratepayer net benefits, but in both cases the participant still faces a net cost while the ratepayer still receives a net benefit.

Figure 41: NPV Net Benefit, Demand Charge Sensitivity



4.5.5 UTILITY SCALE RENEWABLE PPA PRICE

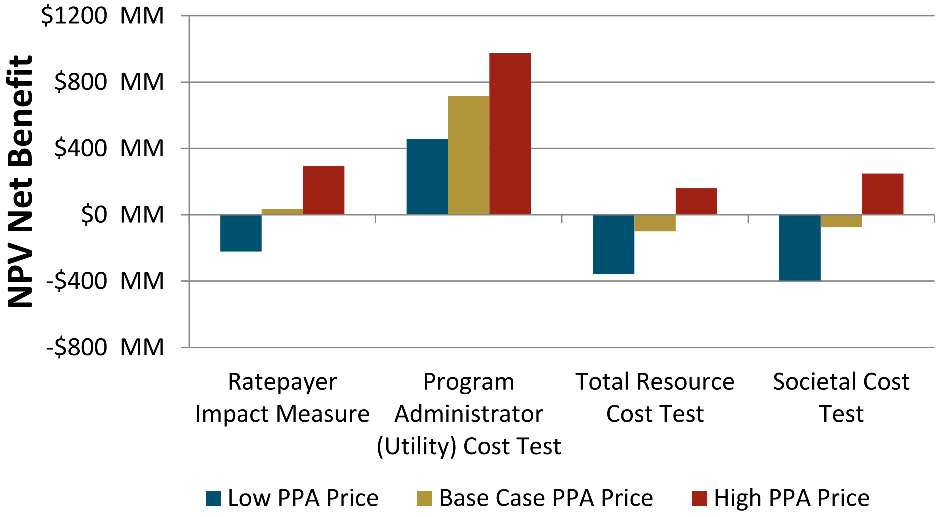
As was demonstrated throughout the results section, renewable NEM generation reduces utility RPS compliance obligations, or the amount of additional renewable energy that NV Energy is required to procure. The RPS policy causes this analysis to be largely a comparison of distributed and utility-scale renewables. Consequently, the relative capital costs of NEM systems and utility-scale renewables are a key driver of the cost-effectiveness results.

There is a fair amount of uncertainty surrounding the cost of procuring utility-scale renewable resources. There is typically a delay in the publicly-available PV capital cost numbers, and many developers have an incentive to report aggressive cost estimates. This sensitivity evaluates the cost of utility-scale renewable power at three different PPA contract levels. We believe that \$80/MWh and \$120/MWh are reasonable bounds on the likely utility-scale PV PPA price. This price does not include integration or transmission costs.

	Utility-Scale Renewable PPA Price
Low	\$80/MWh
Base Case	\$100/MWh
High	\$120/MWh

This sensitivity affects all cost tests except for the PCT. As shown in Figure 42, this assumption about PPA price has the potential to substantially impact results. In the RIM, TRC, and SCT, the difference between a low PPA price and high PPA price is enough to switch from net costs to net benefits.

Figure 42: NPV Net Benefit, Utility-Scale Renewable PPA Price Sensitivity



5 Macroeconomic Impacts of Renewable Energy Policy[25]

It is important for policy makers to understand the impact of renewable energy programs on jobs and the economy, but it can be difficult to accurately quantify the macroeconomic implications of a specific policy. The aim of this section is to provide an understanding of the methodological approaches used to assess the macroeconomic impacts of renewable policies, review their application in the literature, and use previous studies to make inferences about the macroeconomic impact of NEM in Nevada. We first provide a brief overview of economic impact analysis and define terms frequently used to measure impacts. This is followed by a review of modeling approaches used in economic impact analysis, including the strengths and weaknesses of each approach. We then discuss the application of different models through a literature review, and explain differences in results. Finally, we discuss the potential impacts of distributed generation policy on the Nevada economy.

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[25] All literature referenced in this section can be found in Section 7.4.

5.1 Overview of Economic Impacts

Economic impact analysis attempts to quantify the effect of an investment, policy or project on the economy of a region. Economic impacts are typically measured as changes in: (1) *output*, the total value of production; (2) *income* (value added), which is comprised of worker wages and business income, and excludes the purchase of intermediate goods; and (3) *jobs* (employment), which are typically expressed in full-time equivalent years (FTE-years).

These impacts are typically attributed to direct, indirect and induced effects. Direct effects reflect changes in economic activity for industries that receive the initial change in investment (final demand). Indirect effects reflect changes in economic activity of upstream industries responding to meet the change in final demand. Induced effects reflect changes in economic activity resulting from income generated by the direct and indirect activity. The direct effect of a new distributed solar PV installation would be construction jobs at the installation site. Indirect effects would include new jobs in the steel and silicon industries resulting from increased output, and an induced effect would be a construction worker buying a new truck with additional wages earned from the direct and indirect activity.

Economic impact analysis studies can be classified into two groups: gross economic impact studies and net economic impact studies. Gross economic impact studies only consider the positive (stimulus) effects of a given project or policy on the economy. Results from these studies represent the upper bound of estimated economic impacts. In contrast, net economic impact studies also consider negative (contractionary) effects from a given project or policy.

For example, a gross economic impact study assessing the construction of a new solar PV plant would measure only positive changes in employment during the construction and operating phases of the project. A net economic impact study would also include potential contractionary impacts such as: (1) the displacement of fossil fuel energy, which decreases jobs and economic activity in industries servicing conventional energy; and (2) increases in average retail electricity rates that increase production costs and reduce household income, and, depending on price and substitution elasticities, potentially lead to decreases in total employment and income. Rigorous analysis includes both positive and negative impacts, but not all model types are suited to capturing net impacts.

5.2 Models Used in Economic Impact Analysis

This section provides a brief explanation of the common economic modeling approaches.[26]

5.2.1 INPUT-OUTPUT

Input-Output (I-O) models measure direct, indirect and induced effects on gross output, value added (income), and employment as a result of changing final demand for a given sector or sectors in an economy. I-O models rely on historical economic data, and they provide a "snapshot" of the economy.

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[26] This section excludes a complete description of econometrics models, which are used to estimate a statistical relationship between macroeconomic indicators (ex. employment) and explanatory variables (ex. wind project investment). These models require multiple years of historical data to estimate a relationship, but they may be less useful for forecasting, because past relationships may not hold in the future. See Brown et al. (2012) for an example of the economic impacts of wind power development in U.S. counties.

Although I-O multipliers capture direct, indirect and induced effects, they assume that changes in demand do not lead to changes in prices, or subsequently in what firms and people choose to buy. In reality, the production structure of an economy changes as the price of inputs (labor, capital and intermediate input supply) changes, and the final demand structure changes as income (labor and capital) and the price of goods and services changes. The most widely used I-O model is IMPLAN, which draws on economic data from the national level (Bureau of Economic Analysis). IMPLAN is a “fixed-proportions” model, which means that economic shocks do not affect prices within the model; the economic pie grows or shrinks in perfect proportion with the shock. This assumption is difficult to defend, particularly over a longer timeframe. A shock of higher electricity prices, for instance, may reduce intermediate and final consumption almost proportionally in the short term, but over the longer term at least some amount of adjustment to prices would be expected.

5.2.2 COMPUTABLE GENERAL EQUILIBRIUM

Computable general equilibrium (CGE) models expand upon I-O models by allowing prices to adjust so that goods, services and factors of production (labor and capital) achieve supply-demand equilibrium. For instance, an increase in demand for steel would lead to higher steel prices, which might increase the cost of producing cars. As a result, consumers would respond to higher car prices by reducing car consumption, which would reduce demand for steel, and so on. Impacts on employment and income depend on the net result of these interactions, which could be positive or negative.

CGE models are typically used to assess policies that are expected to have large economy-wide impacts and result in a new equilibrium. Examples of CGE models include the Applied Dynamic Analysis of the Global Economy (ADAGE) Model, which represents the entire U.S. economy, and the Berkeley Energy and Resources (BEAR) model that represents the California economy.[27] The disadvantages of CGE models is that they are very expensive, require significant inputs and their "black box" nature makes it difficult to interpret what is driving the results.

5.2.3 HYBRID

Hybrid models combine elements of I-O, CGE and econometric models. The most widely used hybrid model is REMI, which includes most CGE functionality, but it differs from CGE models in that it does not solve for equilibrium supply-demand in all markets for every period. Like I-O models, the greatest strength of REMI is that it is transparent, fully documented and has been used extensively in public stakeholder processes, primarily to evaluate infrastructure projects. In addition, REMI captures both positive and negative economic shocks, and includes price effects. REMI's most important limitation compared to CGE or econometric models is its limited ability to allow for endogenous response. This means that anticipated economic shocks (for example rate impacts) need to be hardwired into the model as inputs, rather than allowing the model to capture the adjustment internally.

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[27] ADAGE is capable of assessing energy and environmental policies at the national and U.S. state levels, and BEAR has been used by assess the economic impacts of California greenhouse gas policy. See CARB (2010)b.

5.2.4 ANALYTICAL

Analytical models estimate the job impacts of renewables by multiplying incremental renewable capacity (in MW) or energy (in GWh) by employment multipliers (in jobs per MW or GWh). These employment multipliers are technology-specific, and are typically based on historical surveys or selective outputs from I-O tables.

For example, Wei et al. (2010) developed the Green Jobs Calculator to estimate the employment impacts of future renewable and energy efficiency scenarios through 2030.[28] Technology-specific employment multipliers were developed by surveying fifteen existing studies, and converting these estimates into jobs per GWh of energy production. Another commonly used analytical model is the Jobs and Economic Development (JEDI) Model developed by the National Renewable Energy Laboratory (NREL).[29] JEDI uses outputs from IMPLAN, an I-O model, to develop economic multipliers for renewable technologies installed across various regions of the United States. Analytical models are simple, transparent and typically free, but they only estimate gross expansionary impacts of a project or policy, and fail to include broader economic impacts.

5.2.5 SUMMARY OF MODELS

Table 30 summarizes the advantages and disadvantages of each the types of models used in economic analysis.

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[28] See RAEL (2010) for a description of the Green Jobs Calculator.

[29] See NREL (2013) for a description of the JEDI model.

Table 30: Overview of Alternative Economic Impact Analysis Models

Model	Description	Examples
Input-Output (I-O)	Advantages • Provides for intuitive interpretation of results; linear nature makes results transparent • I-O techniques are well understood Disadvantages • Assumes fixed proportions (no change in structure), no resource constraints, and no price behavior • Assumptions hold only under a very limited number of circumstances	IMPLAN
Computable General Equilibrium (CGE)	Advantages • Comprehensive model of economy, with market participants choosing quantities in response to price Disadvantages • Tends to be expensive and require significant data inputs • Can be a "black box"; often difficult to determine what is driving the results	ADAGE; BEAR
Hybrid	Advantages • Captures net economy-wide effects • Bottom-up analytical approach allows for adding local detail (e.g., on population and labor supply) • Extensively used and well documented Disadvantages • Typically simpler functionality than CGE models; less sensitive to price changes • Complexity reduces transparency in results • Relatively expensive	REMI
Analytical	Advantages • Simple and intuitive • Free and transparent • Straightforward sensitivity analysis	JEDI; Green Jobs Calculator

Model	Description	Examples
	Disadvantages • May neglect or poorly approximate indirect and/or induced jobs • Always neglects negative impacts • Large variation in employment factors for identical technical (up to a scale of four) • Assumes the economy is static	

5.3 Literature Review

We surveyed a full spectrum of existing literature, including peer-reviewed papers, consultant reports, advocacy reports and government reports. Our review includes studies of individual renewable energy plants, transmission projects to deliver the energy, RPS policies, and GHG policies that include both RPS and energy efficiency measures. We summarize the studies that we analyzed by the type of model they employed in Table 31 through Table 34 below.

Table 31: Studies Using Input-Output Models

Author (Year)	Title	Region	Technology or Policy	Study Results
Clean Energy Project (2013)	The Economic Impact of Renewable Portfolio Standard Changes	NV	RPS Policy	+20,000 to +80,000 job-years
Hausman et al. (2012)	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	NV	Renewables and Transmission	+400 to 1,290 jobs
Applied Economics (2011)	Economic Impacts of Renewable Transmission and Solar Photovoltaic Plants on the State of Arizona	AZ	Solar PV and Transmission	+44 jobs
Arik and Penn (2011)	Green Jobs in Tennessee: Economic Impact of Selected Green Investments	TN	Green Investment	+17,000 jobs

Notes: IMPLAN model was used across all studies.

Table 32: Studies Using Computable General Equilibrium Models

Author (Year)	Title	Region	Technology or Policy	Study Results
Tuerck et al. (2013)	RPS: A Recipe for Economic Decline	NV	RPS Policy	Employment: -590 to -3,070 jobs
CARB (2010)a	Proposed Regulation for a California Renewable Electricity Standard	CA	RPS Policy	-0.1 to -0.2% impact on output, income, and employment
CARB (2010)b	Updated Economic Analysis of California's Climate Change Scoping Plan	CA	GHG Policies	GSP: -0.2 to -1.9% Income: 0.1% to -1.6% Employment: 0.0% to -2.5%
Roland-Holst (2010)	Real Incomes, Employment, and California Climate Policy	CA	GHG Policies	Employment: -0.61% to +3.1% GSP: -0.67% to +4.44%

Notes: models used include STAMP, E-DRAM and BEAR.

Table 33: Studies Using Hybrid Models

Author (Year)	Title	Region	Technology or Policy	Study Results
NYSERDA (2012)	New York Solar Study: An Analysis of the Benefits and Costs of Increasing Generation from Photovoltaic Devices in New York	NY	Solar PV	Employment: -2,500 to +700 jobs/year
Rose et al. (2011)	The Impacts of Greenhouse Gas Mitigation Policy Options on the Pennsylvania State Economy	PA	GHG Policy	Employment: +0.52% GSP: +0.31%
Rose et al. (2010)	Impacts of Climate Policy on the California Economy	CA	GHG Policy	GSP: +0.3 to +0.5%
Schwer and Riddel (2004)	The Potential Economic Impact of Constructing and Operating Solar Power Generation Facilities in Nevada	NV	Solar CSP	+ 140 to 1,800 jobs/year

Note: the REMI model was used across all studies.

Table 34: Studies Using Analytical Models

Author (Year)	Title	Region	Technology or Policy	Study Results
Vote Solar Initiative and CEP Nevada (2011)	Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011	NV	Distributed Solar PV	+ 1,159 jobs per year over the 9-year program
Wei et al. (2010)	Putting renewables and energy efficiency to work: How many jobs can the clean energy industry generate in the US?	US	Renewables and EE	2-6 million cumulative job-years
Vote Solar Initiative (2009)	The Sun Rises on Nevada: Economic and Environmental Impacts of Developing 2,000 MW of Large-Scale Solar Power Plants	NV	Solar CSP	Permanent full-time O&M jobs: 1,200 jobs Construction-phase Jobs (avg/yr for 6 years): 5,900 jobs/yr

Note: models used include the JEDI Model and Green Jobs Calculator.

The literature implications can be summarized by four key findings:

- **Finding #1: Studies that employ simple analytical and I-O models to analyze renewable energy projects and GHG policies always show positive impacts, but they often explicitly exclude contractionary impacts or approximate negative impacts in a crude manner**

As discussed in Section 5.2, analytical and I-O models are inherently unable to model negative impacts except as crude approximations. In practice, most studies based on analytical and I-O models do not attempt to even crudely approximate negative relationships. This limited functionality imposes a bias in the positive direction.

As shown in Table 34, studies that employed analytical models exclusively produced study results showing gross positive impacts. All of these studies used the JEDI model, which only models positive, linear relationships between sector-specific demand (i.e. demand for PV installations) and macroeconomic impacts.

The studies that employed I-O models also only show positive impacts. Table 31 summarizes the results of these studies, which all employed the IMPLAN model. Like the JEDI model, the IMPLAN model assumes historical, positive inter-industry relationships between sector-specific expenditure and macroeconomic outcomes. Any increase in investment (ex. increased renewables) will inherently result in a positive macroeconomic impact. The studies we reviewed only quantified the economic impacts of additional spending to construct renewable facilities, and they failed to take into account how renewables may change electricity rates and displace other forms of energy. This inherently leads to model results showing gross positive impacts from spending on renewables.

- **Finding #2: Studies that comprehensively capture net impacts by using complex models, such as computable general equilibrium and hybrid models, show slight positive or negative impacts**

CGE and hybrid models are well suited to estimate the economy-wide impacts of policy, because they comprehensively measure both positive and negative economic impacts, including price effects. Of the eight analyses we reviewed that used CGE or hybrid models to estimate the net macroeconomic impacts of renewables, RPS policies, and GHG policies, half of them estimate a net negative impact. As summarized in Table 32 and Table 33, two of the studies found conclusive evidence that the net impact was negative, three found conclusive evidence that the impact was positive, and three found that an impact of zero was within the likely margin of error. Even the positive and negative estimates were small relative to the size of the economy studied. All of the macroeconomic impacts estimates roughly fell within a +/-3% range.

+ Finding #3: Analyses that have looked at renewables and efficiency together often produce positive net economic impacts because the productivity-enhancing effects of energy efficiency tend to outweigh the effect of rate increases from renewables

Many of the studies that employed CGE or hybrid models were used to estimate the macroeconomic impacts of GHG policies, which include both RPS and energy efficiency programs. It is likely that the positive net impact of energy efficiency measures counteracted the negative impact of renewables in these studies.

Cost-effective energy efficiency programs generally undergo a thorough cost-effectiveness analysis before they are approved. Consequently, energy efficiency programs that are implemented generally benefit ratepayers. The resulting reduction in energy bills provides households with additional income to spend on other goods and services. This widespread boost in consumption has a multiplier effect on the economy. Conversely, if renewable programs cause ratepayers to pay more for electricity, then non-participating ratepayers will have less money to spend on other goods and services. Even if participants spend more on other goods and services, there are typically more non-participating ratepayers whose goods and service consumption will decrease. This will have a contractionary impact on the economy.

The literature provides evidence that positive net impacts of energy efficiency measures often counteract negative net impacts of renewables. For example, CARB's analysis of California's 33% RPS found slight negative employment impacts, but Roland-Holst (2010) found slight positive employment impacts from California's greenhouse gas reduction policies. Roland-Holst (2010) cited energy efficiency gains as a key driver of the sign of their results.

+ **Finding #4: Comprehensive analyses that isolate the macroeconomic impacts of renewable policies show small, negative impacts. These negative impacts are driven by the contractionary effects of rate increases.**

Both of the studies that used CGE models to estimate the net macroeconomic impacts of RPS policies found small, negative net impacts. As portrayed in Table 32, Tuerck et al. (2013) found a net jobs reduction of 590-3,070 jobs due to the Nevada RPS policy. The 2010 California Air Resources Board (CARB) study found very slight reductions in employment (-0.08%), income (-0.16% to -0.17%) and gross state product (-0.17% to -0.18%). CARB found that employment increases in industries that support renewable electricity generation, but retail rate increases cause employment to decrease in other industries, resulting in a net reduction in employment. We note that these impacts are small given the size of the California labor force and economy.

The one comprehensive study that employed a hybrid model to analyze the impacts of solar PV also estimated a net macroeconomic cost under base case assumptions.[30] New York State Energy Research and Development Authority (NYSERDA) studied the net economic impacts of installing 5,000 MW of solar PV by 2025 using REMI. The modeling results showed that the policy will create jobs directly related to the PV industry, but the net impact on the economy will be negative due to increased retail electricity rates. The base case shows a net job loss of 750 jobs year, and a reduction in GSP by $3 billion between 2013 and 2049 (an annual decrease of less than 0.1%). Sensitivity analyses include: (a)

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[30] We exclude the Schwer and Riddel (2004) study from this section because it does not include a discussion on who pays for the Solar CSP systems or mention including the associated contractionary impacts.

+700 jobs per year in the Low PV Cost Scenario; and (b) -2,500 jobs per year in the High PV Cost Scenario.[31] Note that the capacity analyzed in this study was over 16x greater than the NEM capacity forecasted in Nevada through 2016.

5.4 Conclusion

We can leverage existing studies on the macroeconomic impacts of renewable policies that use complex CGE and hybrid models to infer that the macroeconomic impacts of NEM installed through 2016 in Nevada will likely be very small and could potentially be positive or negative. Our review of alternative economic impact analysis models shows that accurately analyzing the net macroeconomic impacts of renewable energy policies requires the use of complex models, such as CGE or hybrid models, that can comprehensively capture positive and negative direct, indirect, and induced effects as well as supply-demand equilibriums. The simpler models used in studies reviewed, such as the IMPAN I-O model and the JEDI analytical model, are inherently biased in the positive direction.

State agencies across the U.S. have already used CGE and hybrid models to evaluate various renewable policies, and they consistently find slight negative impacts. Existing studies indicate that the solar industry does indeed create jobs, but the negative impact of average electricity retail rate increases tends to outweigh the positive impacts by a small margin. This study, however, finds that NEM will most likely not increase rates in Nevada. We also find that NEM will

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[31] The Low Cost Scenario assumes solar PV costs reach the DOE SunShot goal and federal tax credits are extended through 2025. The High Cost Scenario assumes solar PV costs maintain their long-term historical trends, and federal tax credits revert to a pre-federal stimulus level following expiration in 2016. See NYSEDRA (2012).

displace or defer substantial utility-sited installations, which is not a key impact in the relevant macroeconomic studies we analyzed. Consequently, it is plausible that NEM could have a positive or negative macroeconomic impact in Nevada.

We stress that the net impacts, possibly positive or negative, will be very small relative to the size of the Nevada economy. A study of the macroeconomic impacts of California's 33% RPS found a -0.1 to -0.2% impact on output, income, and employment. A study of 5,000 MW of solar PV capacity in New York estimated a net loss of 750 jobs year and a 0.1% reduction of GSP. The installed NEM capacity forecasted in Nevada through 2016 is more than a degree of magnitude smaller than these studies.

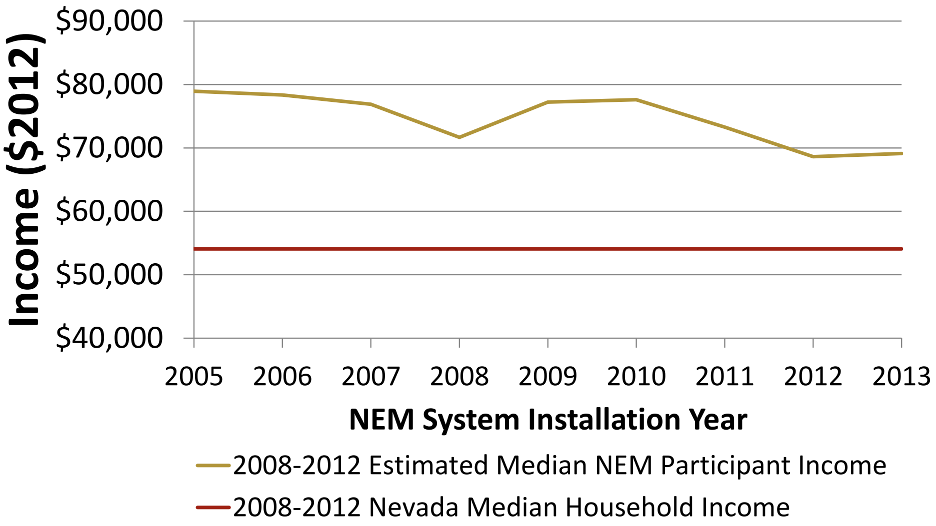
6 Demographic Analysis

We explored two key demographic indicators of NEM participants: household income and population density (as defined by a binary urban/rural classification). We calculated demographic statistics by assigning NEM participant service addresses to 2010 U.S. census block groups, which are more granular and homogenous than the more commonly reported zip code regions. We estimated demographic information of NEM participants based on the demographic information of these census block groups. We then compared these demographics to the demographics of typical Nevada residents.

6.1 Household Income

We assumed that each NEM participant had an income equal to the 2008-2012 median income of the census block group to which the participant was mapped. Using this information, the estimated median income of all current residential NEM participants is $67,418. Comparatively, Nevada median income over the same period was $54,083. Seventy three percent of NEM participants reside in census block groups with median incomes higher than the statewide median income over the same period. Figure 43 shows how NEM participant incomes have changed over time in relation to median statewide income.

Figure 43: NEM Participant Median Income



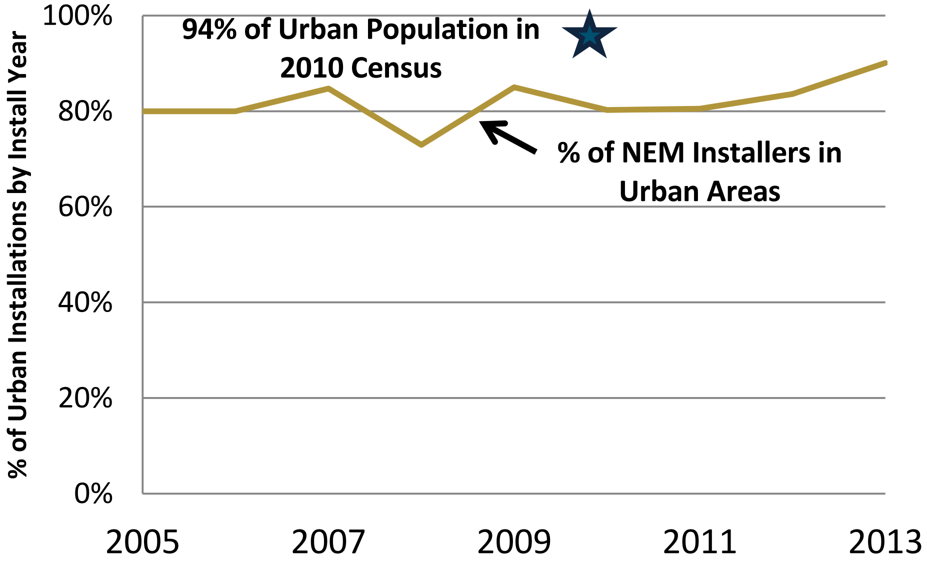
While this graph clearly shows that NEM participants have incomes higher than the statewide median, it makes no statement as to the distributional effects on ratepayers of different income levels. It could be the case that any cost shift from the ratepayers to the NEM participants could come solely from other high income ratepayers, or it could be the case that the cost shift is shared equally among all ratepayers. These issues are all addressed through the rate design process.

6.2 Population Density

Nevada ranks as the second most urban state in the country, with more than 94% of residents living in a U.S. census designated urban area. Urban areas are defined as all territory, population, and housing units located in urbanized areas and in continuously built-out areas of 2,500 or more inhabitants.[32] The binary urban/rural classification is designated based upon what the census defines as a continuously built-out area and is not a function of population density.

In 2010, 81% of all NEM generation systems installed to date were located in urban areas. By the end of 2013, that statistic had increased to 83%. As shown in Figure 44, the annual fraction of urban installations has been relatively flat over time, with a slight increase in the in recent years. Given these historical statistics and the high percentage of Nevadans living in urban areas, we expect that the vast majority of forecasted NEM capacity will continue to be installed in urban areas.

Figure 44: Annual Urban NEM Installations Over Time (% of All Annual Installations)



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[32] Urban/rural definition explained at: http://www.census.gov/geo/reference/pdfs/GARM/Ch12GARM.pdf

7 Appendix

7.1 Additional Results

To complement the general results section, this section shows the levelized net benefit and NPV results for each major categorical breakdown and vintage group. The categories are:

- Customer Class
    - Residential
    - Non-residential
- Utility
    - NVE North
    - NVE South
- Generator Technology Type
    - PV
    - Wind
- Utility Incentive Status
    - Incentivized
    - Non-Incentivized

7.1.1 RESULTS BY CUSTOMER CLASS

PCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Residential	-$105	-$0.05	-$20	-$0.08	-$62	-$0.05	-$22	-$0.05
Non-Residential	-$31	-$0.01	$43	$0.06	-$53	-$0.03	-$20	-$0.03

RIM

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Residential	$56	$0.03	-$10	-$0.04	$63	$0.05	$1	$0.00
Non-Residential	-$20	-$0.01	-$132	-$0.18	$105	$0.05	$6	$0.01

PACT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Residential	$323	$0.15	$21	$0.08	$235	$0.17	$65	$0.13
Non-Residential	$394	$0.11	-$49	-$0.07	$346	$0.17	$95	$0.13

TRC

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Residential	-$48	-$0.02	-$30	-$0.11	$1	$0.00	-$21	-$0.04
Non-Residential	-$51	-$0.01	-$89	-$0.12	$51	$0.03	-$15	-$0.02

SCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Residential	-$42	-$0.02	-$34	-$0.11	$12	$0.01	-$23	-$0.04
Non-Residential	-$33	-$0.01	-$99	-$0.11	$78	$0.03	-$14	-$0.02

7.1.2 RESULTS BY UTILITY

PCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
NVE North	-$54	-$0.03	$12	$0.02	-$48	-$0.05	-$17	-$0.05
NVE South	-$82	-$0.02	$11	$0.02	-$67	-$0.03	-$26	-$0.03

RIM

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
NVE North	-$41	-$0.02	-$90	-$0.19	$44	$0.05	$4	$0.01
NVE South	$76	$0.02	-$52	-$0.10	$123	$0.05	$3	$0.00

PACT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
NVE North	$150	$0.09	-$40	-$0.08	$147	$0.16	$42	$0.13
NVE South	$567	$0.15	$12	$0.02	$434	$0.18	$118	$0.13

TRC

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
NVE North	-$94	-$0.06	-$78	-$0.16	-$3	$0.00	-$14	-$0.04
NVE South	-$6	$0.00	-$40	-$0.07	$56	$0.02	-$23	-$0.03

SCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
NVE North	-$100	-$0.05	-$89	-$0.16	$3	$0.00	-$15	-$0.04
NVE South	$24	$0.01	-$44	-$0.07	$88	$0.03	-$22	-$0.02

7.1.3 RESULTS BY TECHNOLOGY TYPE

PCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
PV	-$128	-$0.02	$30	$0.03	-$115	-$0.03	-$43	-$0.04
Wind	-$7	-$0.26	-$7	-$0.27	$0	-$0.09	$0	-$0.10

RIM

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
PV	$64	$0.01	-$113	-$0.11	$168	$0.05	$6	$0.01
Wind	-$28	-$0.99	-$28	-$1.06	$0	-$0.01	$0	$0.00

PACT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
PV	$742	$0.13	-$2	$0.00	$581	$0.17	$160	$0.13
Wind	-$25	-$0.90	-$26	-$0.97	$0	$0.08	$0	$0.10

TRC

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
PV	-$64	-$0.01	-$83	-$0.08	$52	$0.02	-$36	-$0.03
Wind	-$35	-$1.25	-$35	-$1.33	$0	-$0.10	$0	-$0.09

SCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
PV	-$34	-$0.01	-$92	-$0.08	$91	$0.02	-$36	-$0.02
Wind	-$41	-$1.24	-$41	-$1.33	$0	-$0.09	$0	-$0.11

7.1.4 RESULTS BY UTILITY INCENTIVE STATUS

PCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Incentivized	-$89	-$0.02	$45	$0.06	-$97	-$0.03	-$37	-$0.03
Non-Incentivized	-$47	-$0.07	-$22	-$0.10	-$19	-$0.06	-$6	-$0.05

RIM

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Incentivized	$49	$0.01	-$137	-$0.17	$174	$0.06	$9	$0.01
Non-Incentivized	-$13	-$0.02	-$5	-$0.02	-$7	-$0.02	-$2	-$0.02

PACT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Incentivized	$648	$0.13	-$48	-$0.06	$546	$0.18	$147	$0.14
Non-Incentivized	$68	$0.10	$20	$0.10	$34	$0.10	$13	$0.11

TRC

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Incentivized	-$40	-$0.01	-$92	-$0.11	$78	$0.03	-$28	-$0.03
Non-Incentivized	-$60	-$0.09	-$27	-$0.13	-$25	-$0.08	-$8	-$0.07

SCT

	All Vintages		Existing (through 2013)		2014/2015		2016	
	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh	NPV ($MM)	$/kWh
Incentivized	-$8	$0.00	-$103	-$0.11	$119	$0.03	-$27	-$0.02
Non-Incentivized	-$67	-$0.09	-$30	-$0.12	-$28	-$0.07	-$9	-$0.06

7.2 System Cost *Pro Forma*

The *pro forma* financial model calculates the levelized NEM system capital and O&M costs, including all utility and federal incentives. The financial calculations assume that all systems are owned by third parties and financed with PPAs, where the PPA price that the customer pays is equal to the net system costs levelized over the PPA contract length.

Table 35 shows our active financing cost assumptions. The Nevada NEM Pro Forma Financial Calculator model optimizes debt and equity shares in order to reach a target debt service coverage ratio of 1.4.

Table 35: WACC and Cost of Debt Assumptions

	After Tax WACC	Cost of Debt
2004	9.00%	7.25%
2005	9.00%	7.25%
2006	9.00%	7.50%
2007	9.00%	7.50%
2008	8.70%	6.75%
2009	8.50%	6.50%
2010	8.50%	6.50%
2011	8.25%	6.05%
2012	8.25%	5.40%
2013	8.25%	5.40%
2014	8.25%	6.05%
2015	8.50%	6.50%
2016	8.50%	6.50%

Table 36 lists other key financing input assumptions to the pro forma model. These inputs apply to all system types modeled.

Table 36: Additional Financing Inputs

Input	Value
MACRS Depreciation Term	5 years[33]
Federal Income Tax	35%
State Income Tax	0%
Property Tax	0%[34]
Insurance Cost	0.5% of CapEx
O&M Cost Escalation	2%/year
PPA Term	20 years

Table 37 provides a summary of the capacity factors used in the model. Our bill and avoided cost calculations use hourly generation profiles in order to capture the importance of differences in renewable generation shapes. In the pro forma model, we use simplified representative capacity factors for each technology type and utility to calculate levelized costs.

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[33] Department of the Treasury Internal Revenue Services Publication 946, available at: http://www.irs.gov/pub/irs-pdf/p946.pdf

[34] Nevada Renewable Energy Systems Property tax Exemption , available at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NV02F&re=1&ee=1

Table 37: Capacity Factor Assumptions

	NVE South	NVE North
Solar PV	21%	20%
Existing Wind (2008-2013)	1.7%	2.7%
New Wind (2014-2016)	16.8%	17.8

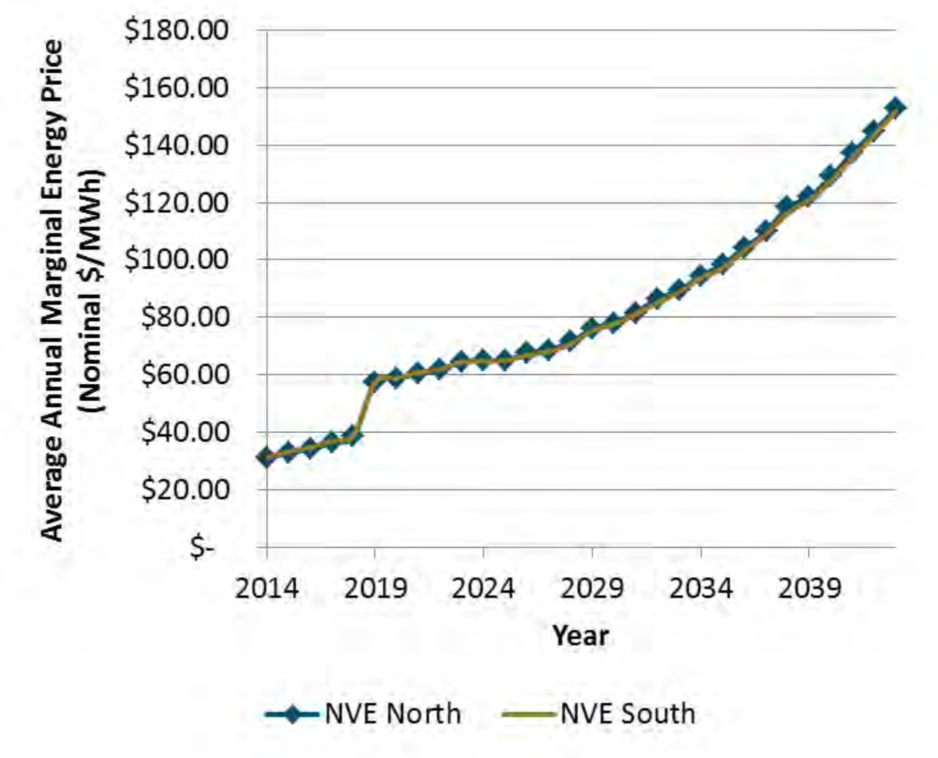
7.3 Avoided Costs

This appendix provides additional information regarding certain critical avoided cost components.

7.3.1 ENERGY COMPONENT

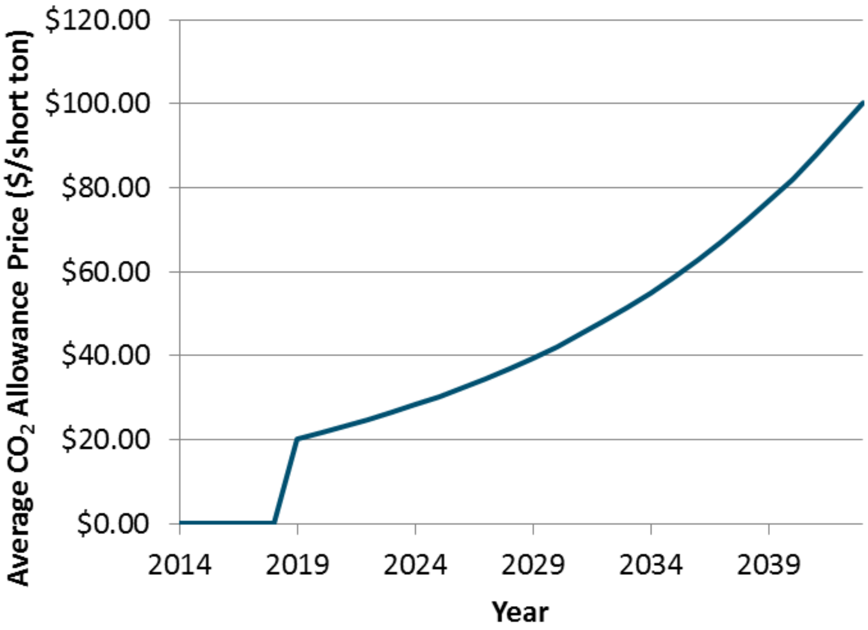
Hourly marginal energy prices from NV Energy's production simulation runs increase over time, as a function of increasing gas prices and the introduction of a carbon allowance price in 2019. Figure 45 below shows the average annual production simulation price for each utility, from 2014 to 2043.

Figure 45: Average Annual Marginal Energy Prices



NV Energy's average energy prices increase significantly in 2019 with the introduction of a regulatory CO_2 emission allowance price. Figure 46 shows NV Energy's IRP carbon price forecast through 2043.

Figure 46: Annual CO_2 Allowance Prices



7.3.2 SYSTEM CAPACITY COMPONENT

The capacity component of avoided costs is defined by a short run value that transitions into a long run value over time. The short run value reflects the fact that both NVE North and NVE South currently have a surplus of available generating capacity; the utilities expect to reach resource balance and add new capacity resources in 2025 and 2018, respectively. The short term capacity value is approximated using the estimated fixed O&M cost of a gas combustion turbine (CT), representing the cost of maintaining an existing capacity resource. As the utilities approach resource balance, the capacity value gradually approaches its long run value, defined as the capacity residual of a new capacity resource.

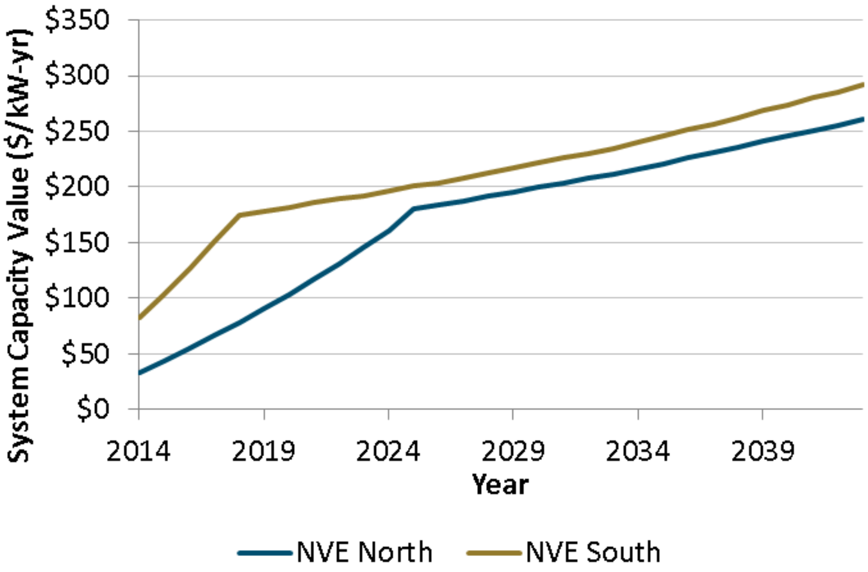
We assume that the new capacity resource for each utility is a natural gas CT. We calculate the capacity residual of the CT by subtracting energy and A/S revenues earned by the resource from the CT's annualized fixed cost. Expected energy and A/S revenues are calculated by dispatching the CT against the production simulation energy prices from NV Energy's IRP (the same prices used to generate the energy component of the avoided costs, including a carbon allowance price). Table 38 lists our assumptions regarding a new gas CT's performance, which determine the resource's dispatch pattern when compared to production simulation prices. The table includes specific assumptions for each utility, as well as the data source for each input value.

Table 38: New Capacity Resource Performance Metrics

Component	NVE North Value	NVE South Value	Data Source
Plant Type	Gas Combustion Turbine	Gas Combustion Turbine	E3 assumption/IRP
Heat Rate	9,200	9,200	IRP (assumes LMS100 Turbine)
Variable O&M Cost	$3.40/MWh (2013$)	$3.40/MWh (2013$)	IRP
Plant Cost Escalation Rate	2%/year	2%/year	E3 assumption
Resource Balance Year	2025	2018	2013 IRP
New Capacity Resource Annualized Fixed Cost	$128.97/kW-yr (2013$)	$142.67/kW-yr (2011$)	2011/2013 GRCs
Existing Combustion Turbine Fixed O&M Cost	$20/kW-yr (2013$)	$20/kW-yr (2013$)	E3 assumption
Plant Cost Escalation Rate	2%/year	2%/year	E3 assumption

Figure 47 shows the resulting annual system capacity value for each utility. The values gradually increase until reaching the capacity residual in the resource balance year, and then escalate at inflation through the end of the study period.

Figure 47: Annual System Capacity Value



7.3.3 TRANSMISSION AND DISTRIBUTION COMPONENTS

NV Energy provided transmission and distribution annualized fixed costs from each utility’s most recent general rate case.

Table 39: Transmission and Distribution Capacity Annualized Fixed Costs

	NVE North (2013$)	NVE South (2011$)
Transmission Capacity ($/kW-yr)	$17.15	$24.62
Distribution Capacity ($/kW-yr)	$102.83	$46.55

7.3.4 AVOIDED RPS VALUE

As described in Section 3.6, NEM generation earns substantial value by avoiding utility purchases of utility-sited renewables to meet the Nevada RPS policy. The avoided RPS value is defined by the net cost of the avoided renewable generation, meaning its total cost minus its total value to the system. Our analysis assumes that the avoided renewable resource is central-station PV. The total costs of the RPS resource are the busbar cost (PPA price), resource integration cost, and transmission cost. The benefits of the RPS resource are the energy and capacity values of a central-station PV installation, calculated using the hourly avoided costs of energy and system capacity.

Table 40 shows the cost inputs used in the avoided RPS value calculation for each utility, and it lists a data source for each value. It is important to note that, due to forecasted increases in gas prices, NV Energy’s IRP energy costs increase significantly over time (as shown in Figure 45). In contrast, the busbar and transmission costs of utility-scale solar are expected to remain relatively constant. As a result, the net cost of central-station PV decreases over time, meaning the avoided RPS value decreases with time.

Table 40: RPS Value Inputs

Component	NVE North Value	NVE South Value	Data Source
Marginal Resource Busbar Cost ($/MWh)	$100	$100	E3 WECC Capital Cost Report[35]
Marginal Resource Integration Cost ($/MWh)	$2	$2	Literature review (see Integration Costs section)
Marginal Resource Transmission Cost ($/kW-yr)	$11.22	$11.22	WECC transmission[36]

7.3.5 EXAMPLE ANNUAL AVOIDED COSTS BY COMPONENT

Figure 48 shows the annual average avoided costs by component of a representative DG solar installation in NVE North's territory. The annual avoided costs look very similar for DG installations in NVE South's territory.

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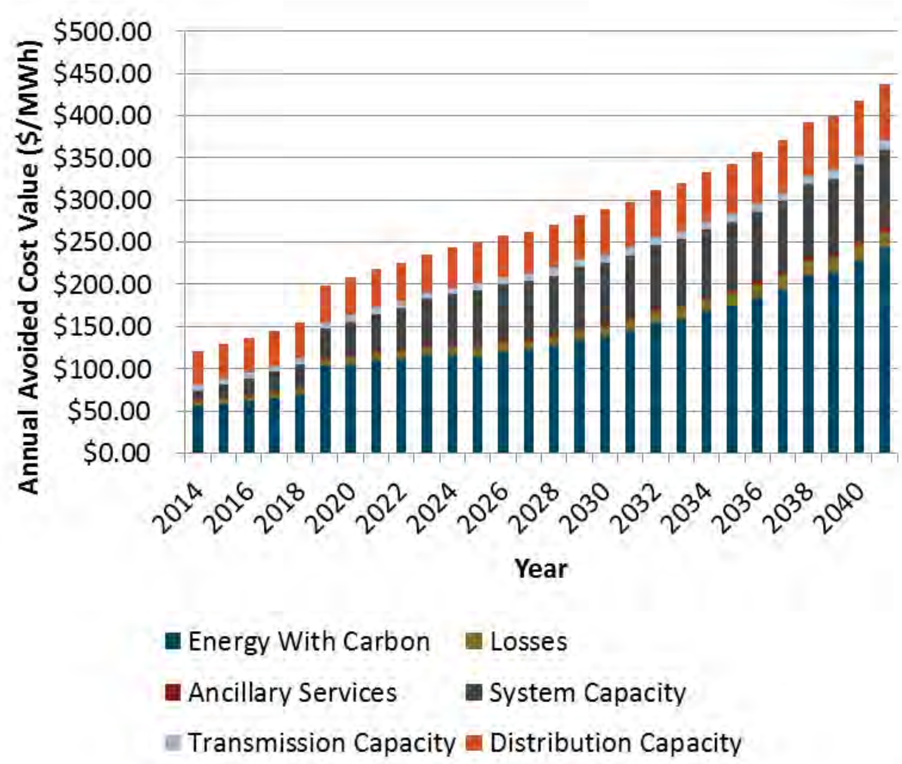
[35] E3 WECC Capital Cost Report

[36] http://www.wecc.biz/Planning/TransmissionExpansion/RTEP/06212010/Lists/Minutes/1/WREZ_Table-Base%20Case.pdf

Figure 48: Example Annual Avoided Cost by Component of a DG Solar Installation in NVE North



7.4 Economic Analysis

This appendix lists the references included in our economic impacts literature review, described in Section 5.

Applied Economics (2011). Economic Impacts of Renewable Transmission and Solar Photovoltaic Plants on the State of Arizona. Available at: http://images.edocket.azcc.gov/docketpdf/0000123557.pdf

Arik, M. and D. Penn (2011). Green Jobs in Tennessee: Economic Impact of Selected Green Investments. Available at: **https://source.tn.gov/admin/gsipub/htmlarea/uploads/MTSU%20Green%20Jobs%20Study.pdf**

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California Air Resources Board (CARB) (2010)b. Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board. Available at: **http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf**

Clean Energy Project (2013). The Economic Impact of Renewable Portfolio Standard Changes. Available at: **http://cleanenergyprojectnv.org/newsroom/applied-analysis-report-details-net-economic-benefits-nevada-cleaning-nevada%E2%80%99s-renewable**

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