A Financial and Policy Analysis of Small Photovoltaic Ownership for Investor-Owned Utility Customers in North Carolina

by

George K. Kataoka

Dr. Timothy L. Johnson, Adviser
May 2013

Masters project submitted in partial fulfillment of the
requirements for the Master of Environmental Management degree in

the Nicholas School of the Environment
of Duke University

2013

ABSTRACT

As a source of clean distributed generation, small solar photovoltaic (PV) systems for residential investor-owned utility (IOU) customers can yield significant benefits to their owners along with a cleaner energy mix, strengthened economy, and improved environment for all citizens of North Carolina. However, the major barriers to small PV investments on a larger scale remain the high upfront costs and poor return on investment. Yet, North Carolina has significant drivers, including declining costs and strong policy, that may make such investments more attractive in the future.

This Master's Project is split into two parts. Part I investigates the current policies and incentives that impact small PV investment decisions for IOU customers in North Carolina. Part II builds off the research gained from Part I in order to quantify the financial attractiveness of such investments for an average Duke and Progress Energy customer. Part II additionally performs scenario and sensitivity analyses to assess if and when certain factors can significantly alter investment decisions.

The results of this project indicate that despite effective policies and incentives in North Carolina, small PV ownership is still a financially unattractive investment—the reference cases yield a net present value (NPV) of less than -$6,000 and -$8,000 for the Progress and Duke customer, respectively. Yet, the impact that such policies and incentives—namely the state and federal investment tax credits—have on these respective NPVs should not be overlooked as they effectively increase the NPVs more than twofold. At the same time, there are many opportunities to further improve the financial attractiveness of such investments, including improvements in net metering policies, the state's Renewable Energy & Energy Efficiency Portfolio Standard requirements, and demand for Solar Renewable Energy Credits.

In such manner, this report does not offer specific policy or financial recommendations. Rather, it is an in-depth analysis of existing policies and economic factors intended to provide both qualitative and quantitative insight for the benefit of small PV investors, the PV industry, and decision makers in North Carolina.

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INTRODUCTION

Solar photovoltaic (PV) systems of all capacities have become more and more accessible and affordable for North Carolinians for the past decade. A report[1] released early in 2012 by the North Carolina Sustainable Energy Association (NCSEA) found that with declining installed costs and effective policies incentivizing PV installations, some systems (e.g., greater than 10 kW for certain electric utilities) are already cost competitive[2] with retail electricity prices in North Carolina. However, for systems 10 kW or smaller, the report concludes that cost competitiveness with retail residential electricity rates in North Carolina will not be realized until 2020.

Small PV systems, categorized by this Master's Project as 10 kW_{DC} or smaller in capacity, are beneficial for North Carolinians for many reasons. First, residential electricity consumers in North Carolina desire more accessible and affordable clean energy sources, especially if utilities are not providing enough clean energy sources as demanded. Small PV systems have the potential to fill part of this void because of the state's good solar radiation resource, strong policy environment, and declining installed costs. Second, small PV systems used by residential customers provide benefits as a form of distributed generation (DG). DG has many benefits beyond electric bill savings and reduced greenhouse gas and criteria pollutant emissions—it has the potential to reduce transmission and distribution (T&D) losses and congestion costs, increase reliability for consumers, improve power quality, reduce peak power requirements for utilities, reduce vulnerability to terrorism, and defer additional generation capacity, such as new natural gas-fired power plants. Third, investing in a small PV system is becoming more and more an attractive financial investment. By either selling energy or offsetting consumption via net metering coupled with the revenue from selling renewable energy credits[3] (RECs), small PV systems can help save a significant amount of money while potentially yielding positive returns over the course of the life of the system. Fourth, increased small PV installations can be a benefit to North Carolina's economy. By increasing demand for these modules and installations,

[1] North Carolina Sustainable Energy Association. (2012, February). *Levelized Cost of Solar Photovoltaics in North Carolina*.
[2] Cost-competitiveness was measured by NCSEA's report in terms of grid parity, which is the point at which the amortized cost of a solar PV system becomes equal to retail electricity prices in North Carolina.
[3] A REC is a tradable, non-tangible energy commodity representing proof that 1 MWh of electricity was generated from an eligible renewable energy resource. An SREC is a REC specifically generated by an eligible solar energy resource.

clean energy suppliers can receive a higher volume of sales, jobs can be maintained and created, and economic activity can increase, yielding increased tax revenue.

Despite these factors that impact small PV investment decisions, one of the key drivers for increased small PV installations on a larger scale is the return on investment, that is, whether the financial benefits meet or exceed the financial costs. For this reason, this report analyzes the financial attractiveness of small PV systems for residential investor-owned utility (IOU) customers in North Carolina using investment rules widely used by investors, namely the net present value (NPV) and internal rate of return (IRR). It is presumed by this study that if a project's NPV is zero or greater using conservative values, it will be financially attractive where increased installations will be seen on a larger scale.

Although there are various sources already investigating the financial attractiveness of small PV systems and the policies driving them, such as NCSEA's report previously discussed, this report examines an area that has yet to be studied in great detail and on a conservative basis. First, many non-academic sources provide overly optimistic estimates for returns on small PV investments. For example, *Solar Power Rocks*, an online source for home solar investment information, estimates a six year payback period and a $27,338 return on investment for a 5 kW system in North Carolina for their given assumptions[4], which include over $12,500 in increased home value and no consideration of the time value of money. Even if such calculations were done meticulously, a more conservative approach can provide insight that these optimistic results cannot. Second, NCSEA's report mentioned earlier is not intended to analyze the benefits of PV systems, such as the intricate hourly-specific benefits from net metering or revenue from selling RECs, which is necessary to calculate values for investment rules. Third, the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory, provides an excellent means to calculate costs and benefits and to provide results in terms of investment rules. Yet, SAM is not currently programmed to calculate specific aspects of small PV operations in North Carolina. For instance, it does not account in detail for net excess generation rules, time-of-use (TOU) tariff rules specific to North Carolina, and customer-made changes in utility tariffs during the duration of the system life.

[4] Solar Power Rocks. (2012 December). *North Carolina Solar Power Rebates, Tax Credits, and Incentives*. Retrieved from www.solarpowerrocks.com.

This report, thus, aims to answer the following questions:

- Currently, how financially attractive is small PV ownership for the average residential Duke and Progress Energy customer in North Carolina?
- What are the policies and incentives available to these customers that impact financial attractiveness of small PV ownership? How effective are they currently?
- In what ways can the financial attractiveness of small PV ownership for these customers be improved?

Duke Energy Carolinas, LLC and Progress Energy Carolinas Inc. (referred to as "Duke" and "Progress" in this report) are the focus of this study because they account for the vast majority of electricity sales in North Carolina, making up more than 70% of state sales in 2010[5]. Duke and Progress are also the largest IOUs in the state, the other being Virginia Electric & Power Co (a.k.a. Dominion North Carolina Power) which provided only 3.2% of total electricity sales in 2010[2]. Hence, due to this majority of sales and the major state policies being primarily focused on IOUs, the average Duke and Progress customer were the focus of this report.

This report is split between two parts. Part I presents the major incentives from policies and incentives that affect small PV ownership for Duke and Progress residential customers. It provides background information and data regarding when the incentive or policy was implemented, how effectively it has incentivized installations, when it will expire (if applicable), who is eligible for it, and the specifications of its rules and requirements. Part I also includes policies that are not currently implemented, but that could effectively incentivize small PV in supplementary or alternative ways. Part II is a financial analysis building off what is presented in Part I. It uses an interactive MS Excel cash flow model created by the author of this study in order to quantify the financial attractiveness of such investments.

The results of this report (including Part I and Part II) are intended to benefit two audiences in particular. First, the results may provide policy and financial insight for residential IOU customers in North Carolina either contemplating investing and/or in support of more clean

[5] U.S. Energy Information Administration. (2010). *EIA-861 "Annual Electric Power Industry Report" data for North Carolina*.

energy in North Carolina. Second, the results may help decision makers in evaluating policies and incentives impacting small PV ownership in North Carolina. This report, as stated, was aimed to provide detailed research and calculations to analyze financial attractiveness and ownership growth on a large scale. Thus, it is meant to help those whose finances can be affected and those whose decisions can affect them.

PART I. MATERIAL AND METHODS

Part I of this report reviews the major clean energy policies and incentives intended to encourage residential PV ownership. It also looks into a few alternative options worth considering other than ownership, such as third-party power purchase agreements. Part I precedes Part II as it provides the background knowledge and information necessary to calculate the financial attractiveness using these policies and incentives. The main sources used in Part I included:

- Database of State Incentives for Renewables & Efficiency (DSIRE)
- North Carolina Utilities Commission (NCUC)
- North Carolina General Assembly
- Interstate Renewable Energy Council (IREC)
- The Vote Solar Initiative
- U.S. Energy Information Administration (EIA)
- North Carolina Department of Revenue
- NC GreenPower
- Various electric utility websites

In some instances, other states' policies and incentives for small PV systems are used as a broad comparison and benchmark for North Carolina. These states include Arizona, Colorado, New Mexico, and Nevada, as their electric utilities are similarly regulated yet have successfully realized large increases in small PV installations for the past decade. However, comparing North Carolina to these other states may be misleading, especially due to significantly different solar radiation resources and retail electricity rates. Thus, comparisons are not meant to be interpreted too strictly or with extensive weight.

PART I. POLICY AND INCENTIVE RESEARCH

Note: In July 2012, Duke completed its $32 billion merger with Progress, creating the largest electric utility in the United States. Although a projection of the structure of rate schedules, PV rebate programs, and other policies regarding customer-sited generation for both utilities are beyond the scope of this study, both respective utility websites state that no changes to service, rates, billing, and existing programs are expected. Thus, this study refers to these utilities operating separately within the context of small PV ownership and residential customers. The Limitations and Further Study section of this report will briefly touch on the implications of the consolidations from this merger.

Key State Policies and Incentives

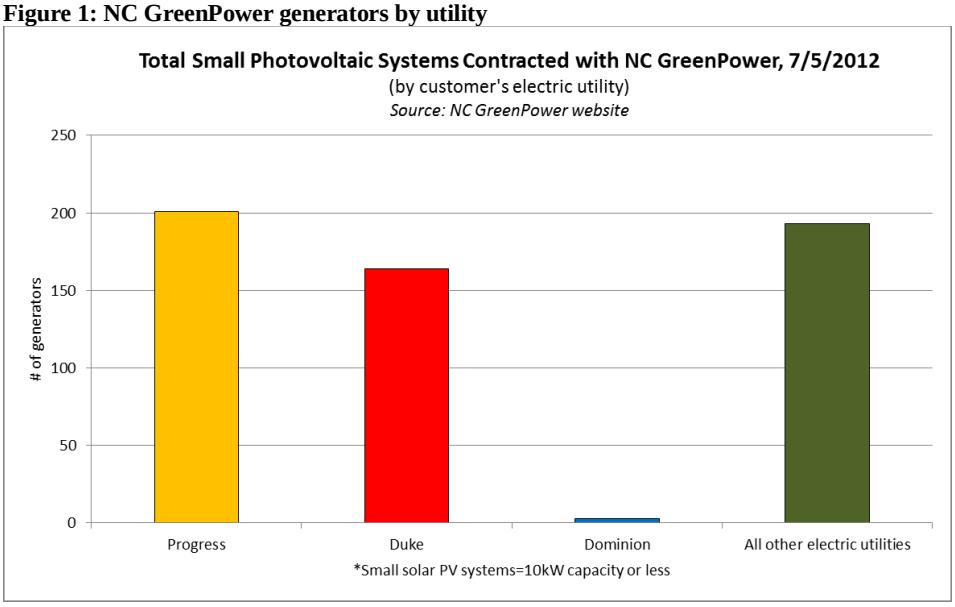
NC GreenPower (2003)

In 2003, NC GreenPower, the first voluntary green power pricing program in the United States, was created in order to help offset the cost of producing solar, wind, small hydro, and biomass energy and integrate more renewable energy sources in the state's electric grid. Once an eligible owner begins a five-year power-purchase agreement (PPA) with their participating utility, as required, the owner will begin receiving performance incentives from NC GreenPower alongside the avoided-cost payments from the PPA. As of December 2012, small PV systems ($\leq 5kW_{AC}$) receive $0.08/kWh from NC GreenPower and a range of $0.04/kWh to $0.09/kWh from their utility (depending on the time the kWh was generated); PV systems greater than $5kW_{AC}$ enter a competitive bidding process. For the $0.08/kWh, NC GreenPower receives all the associated RECs the system generates, which NC GreenPower retires afterwards. The contract is offered for a duration of five years with the option to renew on an annual basis afterwards.

Since NC GreenPower is funded by voluntary contributions, it does not offer contract guarantees. The program is exclusively funded from individuals who purchase 100-kWh blocks of green power, which is currently priced at $4.00 (or $2.50 for large volume-users) per block. Additionally, the initial premium and eligibility rules were much more generous than they are now, with initial premiums for small PV systems being $0.18/kWh and including systems up to $10kW_{AC}$. This decrease in funds and shrinkage in eligibility is due to the declining installed costs of PV systems and the over-subscription of the program.

As of November 2011, NC GreenPower had 35,436 100-kWh blocks of power per month for a total of 42,523,200 kWh of renewable energy delivered to the electric grid for the year[6]. And, as of July 2012, there were 576 small PV, 15 large PV, 6 wind, 2 small hydro, and 3 landfill methane generators contracted with NC GreenPower. As Figure 1 shows, NC GreenPower is currently contracted with more than 350 small PV ($\leq$10kW$_{AC}$) generators that are interconnected with IOUs.

Figure 1: NC GreenPower generators by utility



State Investment Tax Credit (extended in 2005 and 2009)

North Carolina's state investment tax credit began offering tax credits to solar energy generators beginning in the early 1990's. For any capacity PV system, the state offers a 35% personal tax credit—with a credit limit of $10,500 if used for a non-business purpose—for the cost of eligible renewable energy property constructed, purchased, or leased by a taxpayer and placed into service in North Carolina during the taxable year. Additionally, the credit must not exceed 50% of the taxpayer's state tax liability for the year. However, if the credit is not used within the first year, it can be carried over for the next five years.

[6] North Carolina Utilities Commission. (2011, November). *Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina.*

The credit can be taken against franchise tax, income tax, or gross premiums tax. The eligible costs for the credit include the total installed cost less any rebates and discounts. However, the federal investment tax credit is exempt and will not reduce the basis for determining the state investment tax credit. Note, however, that the interaction between this state investment tax credit and state and federal marginal income taxes result in a net credit less than 35%. As a short explanation, the state investment tax credit reduces the total amount paid in state taxes from the perspective of the PV owner household for that year. Due to this reduced amount, when paying federal income taxes, the amount deductible from paid state income taxes is reduced by that same amount, meaning the household will be responsible for paying slightly more in federal income taxes than if the household did not choose to invest in a PV system. This increase is simply the state investment tax credit amount multiplied by the federal marginal income tax rate.

Fortunately, the state investment tax credit was extended in 2005 and 2009 and is currently set to expire in 2017 for personal property. Although only 26 non-business PV projects (for a total of $58,701) generated energy tax credits in the 2005 process year, the North Carolina Department of Revenue reported that 137 non-business PV projects generated $712,957 in energy tax credits in the 2011 process year[7], a greater than 400% increase in projects.

Interconnection Standards (2005; revised in 2008)

North Carolina's interconnection standards apply to all of the state's three IOUs. The *Freeing the Grid 2012* report[8] gives North Carolina an interconnection grade of "B" based on best practices for effective interconnection policies. For certified inverter-based systems up to $10kW_{AC}$, a simplified interconnection process allows for a quicker, less-hassle path to interconnecting a system in North Carolina. This inverter process includes:

- a $100 non-refundable processing fee with an Interconnection Request;
- no liability insurance beyond a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence;
- if the utility requires the customer to install an external disconnect switch, the utility must reimburse the owner of the system for the cost of the switch;
- RECs in general remain the property of the system owner;
- deadlines from the utility (i.e., "transmission provider") following FERC standards:

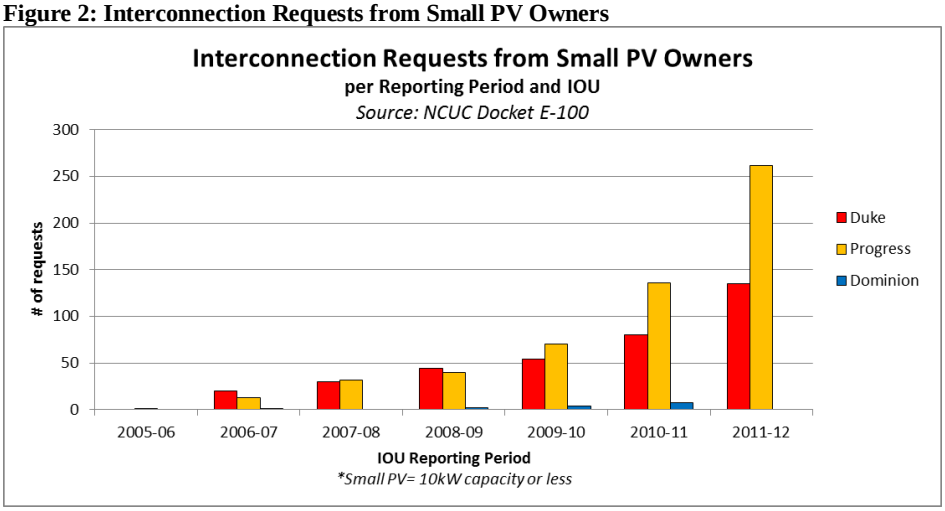
[7] North Carolina Department of Revenue. (2005). *Single Family Energy Projects, 2005, Energy Tax Credits Generated.*
North Carolina Department of Revenue. (2011). *Nonbusiness Energy Projects Energy Tax Credits Generated, Process Year 2011*.
[8] Interstate Renewable Energy Council & The Vote Solar Initiative. (2012 November). *Freeing the Grid 2012*.

- Utility must acknowledge customer receipt of interconnection application within three business days.
- Utility must notify the customer within 10 business days of the receipt of the Interconnection Request as to whether the interconnection request is complete or incomplete.
- Utility has 15 business days to complete screening process to insure customer's generating system can be interconnected safely and reliably.
- If utility requires a witness test, utility must complete test within 10 business days.

As Figure 2 shows, residential customers with Duke and Progress have increased their demand for small PV interconnections since the inception of the state's interconnection standards in 2005. And, from the 2005-2006 to 2011-2012 IOU reporting periods, roughly 92% of reported interconnection requests from small PV owners with IOUs were successfully interconnected[9].

With a grade of "B" from *Freeing the Grid 2012*, North Carolina is comparable to successful regulated states like Colorado, New Mexico, and Nevada, and tops Arizona, which as of 2012 does not have a state interconnection standard (Figure 3). However, since this grade is not solely based on residential PV technologies, many of the improvements that could boost North Carolina to an "A" grade pertain to the larger spectrum of technology capacity sizes, public utilities (i.e., municipally-owned utilities and electric membership corporations), and generating technologies.

Figure 2: Interconnection Requests from Small PV Owners



[9] North Carolina Utilities Commission. (2005-2012). *Docket No. E-100, Sub 101A.*

Figure 3: Freeing the Grid Interconnection Grades

Freeing the Grid **Best Practices for in State Interconnection Policies Grades**						
		Colorado	**New Mexico**	**Nevada**	**Arizona**	**North Carolina**
Interconnection	2008	*C*	*B*	*B*	*C*	*D*
	2012	**B**	**B**	**B**	**N/A***	**B**
		**As of December 2012, Arizona does not have a state interconnection standard*				

Net Metering Standards (2005; amended 2009)

With the 2009 amendment, North Carolina's net metering standards require the state's three IOUs to make net metering available for all eligible generators, including PV systems, up to an individual system capacity of 1MW for commercial customers and 20kW for residential customers. In addition to a high capacity limit, the standards protect residential systems up to 20kW from utility stand-by charges and any other metering charges not also charged to customers who do not net meter and are under the same rate schedule. This removes a significant financial barrier that could otherwise accrue additional, unexpected costs to a small PV owner. Another strength of the state's net metering standards is its lack of an aggregate capacity limit on net metering systems. Originally, the North Carolina Utilities Commission ordered that IOUs only had to make net metering available up to an aggregate limit of 0.2% of each utility's North Carolina jurisdictional retail peak load from the previous year. By removing this limit, net metering will be available throughout every year to eligible systems irrespective of aggregate net metering capacity.

Despite some of these strengths, *Freeing the Grid 2012* gives North Carolina a net metering grade of "D". Prior to the 2009 amendment, North Carolina received a grade of "F". The two major weaknesses of the state's standards are the rules for net excess generation (NEG) and ownership of RECs. NEG is defined as any generated kWh left over after a billing period once retail electricity consumption and on-site generation from the PV system are accounted for. The standards permit NEG to be carried over to the next billing period until the beginning of the summer billing session (i.e., May 31st), when all leftover NEG is surrendered to the utility at no compensation to the system owner. This can be a financial barrier on system capacity size because if a system generates too much, in the context of the customer's electric load, the customer loses valuable energy that could have been used and/or revenue it could have earned.

This can also be problematic for customers whose NEG and generation in May exceed the customer's load in May.

The standards allow customers to net meter under any available rate schedule. However, if the customer elects any tariff other than a time-of-use (TOU) demand tariff, the customer must surrender all its associated RECs to the utility at no compensation. The issue with this rule, despite customers holding ownership of RECs under a TOU demand tariff, is that it devalues on-peak generation for the customer. Under the rule, on-peak generation offsets on-peak consumption and off-peak generation offsets off-peak consumption per billing period. However, all NEG (including on-peak generation) is restricted to offsetting only off-peak generation in the following billing periods. Thus, in addition to surrendering all NEG before the summer billing session to the utility, the customer is left to make a decision between surrendering all RECs with no compensation (on a non-TOU demand tariff) or holding onto RECs at the cost of devalued on-peak generation (on a TOU demand tariff).

In North Carolina, net metering was very unattractive for small PV customers until 2010 and 2011. Figure 4 shows the cumulative amount of requests from small PV customers who submitted interconnection requests and the amount of those requests which were net metering requests. Prior to the 2010-2011 IOU reporting period, very few small PV interconnection requests with IOUs requested the option to net meter. Progress, however, has had almost 300 net metering requests up until the 2011-2012 reporting period largely due to its PV rebate program, SunSense, which began in 2011. Although SunSense recipients must net meter under the TOU demand tariff, they receive substantial incentives with a one-time capacity-based rebate along with monthly capacity-based payments, all in exchange for the RECs associated with the generation.

Based on the 2008 to 2012 *Freeing the Grid* reports, North Carolina compares very poorly to Colorado, New Mexico, Nevada, and Arizona (Figure 5). The results of these net metering policies speak for themselves (Figure 6)—North Carolina IOUs only had 263 reported residential PV net metering customers in December 2011, whereas the other four states examined in this report had customer totals in the thousands with Colorado leading with almost 7,000 in 2010.

Additionally, compared across these states' IOUs, North Carolina IOUs have significantly less net metering residential PV customers (Figure 7). In 2010, Xcel Energy in Colorado alone had more than 25 times more net metering residential PV customers than all North Carolina IOUs combined in December 2011.

Figure 4: Small PV Interconnection and Net Metering Requests

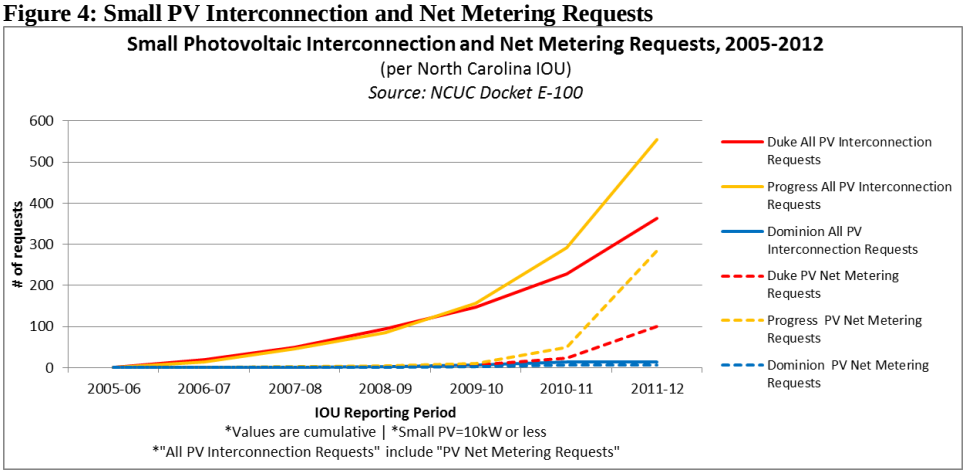


Figure 5: Net Metering Residential PV Customers by State

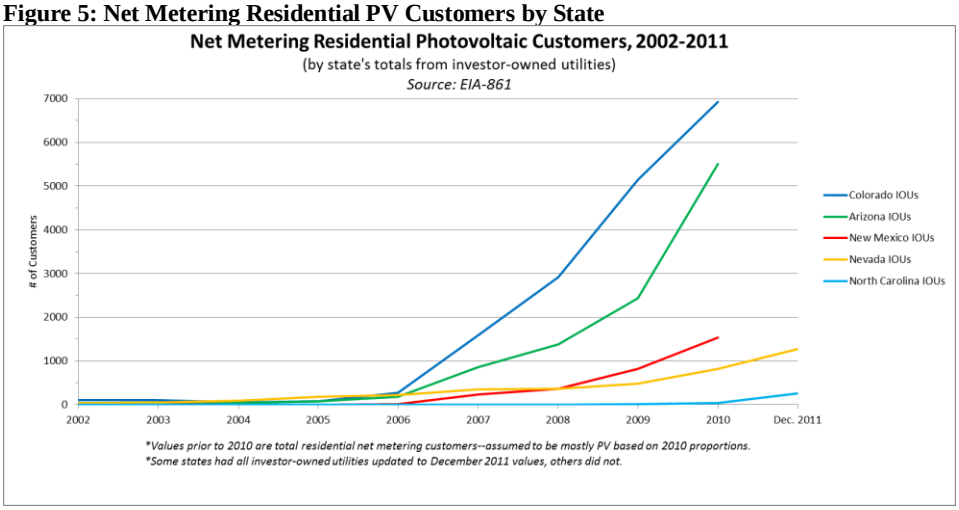


Figure 6: Net Metering Residential PV Customers by Utility

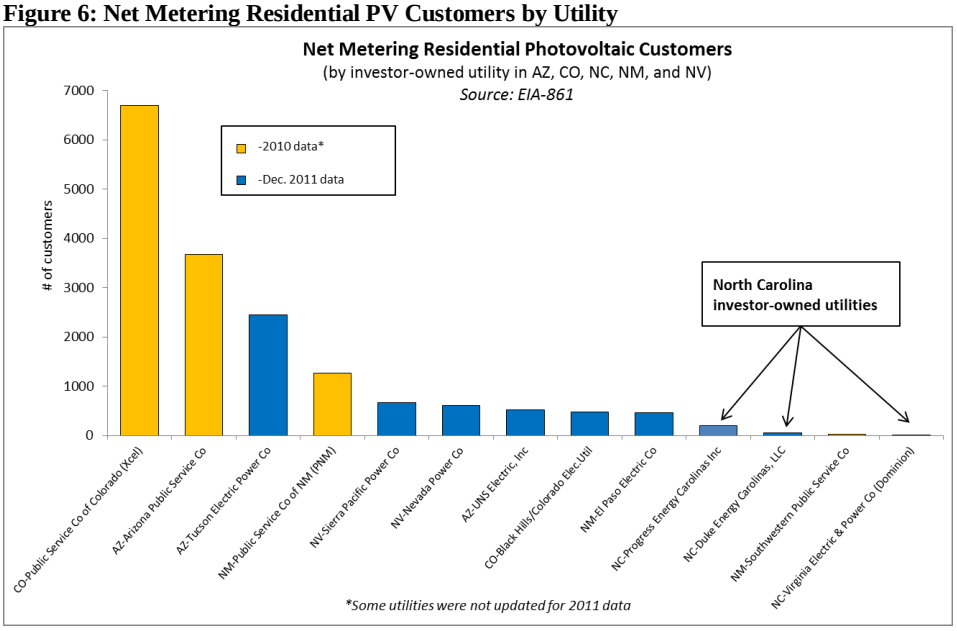


Figure 7: Freeing the Grid Net Metering Grades

Freeing the Grid Best Practices for in State Net Metering Policies Grades						
		Colorado	New Mexico	Nevada	Arizona	North Carolina
Net Metering	2008	*A*	*B*	*B*	*B*	*F*
	2012	**A**	**B**	**B**	**A**	**D**

Solar Access Laws (2007)

In 2007, North Carolina passed a solar rights law. In compliance with this law, North Carolina cities and counties generally may not adopt ordinances prohibiting the installation of certain solar technologies, including solar thermal and PV, for residential property. Although there are some exemptions from protection, such as PV systems visible from the ground under certain specifications, North Carolina's solar rights law reduces the potential siting and zoning barriers of installing solar PV.

Renewable Energy and Energy Efficiency Standard (2007)

With the passing of Senate Bill 3 in 2007, North Carolina became the 25th state to pass a renewable energy portfolio standard (RPS) and the first in the Southeast. Under the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), North Carolina IOUs are required to supply 12.5% of 2020 North Carolina retail electricity sales from clean energy by 2021, and public utilities are required to supply 10% of 2017 retail sales by 2018. Starting in 2010,

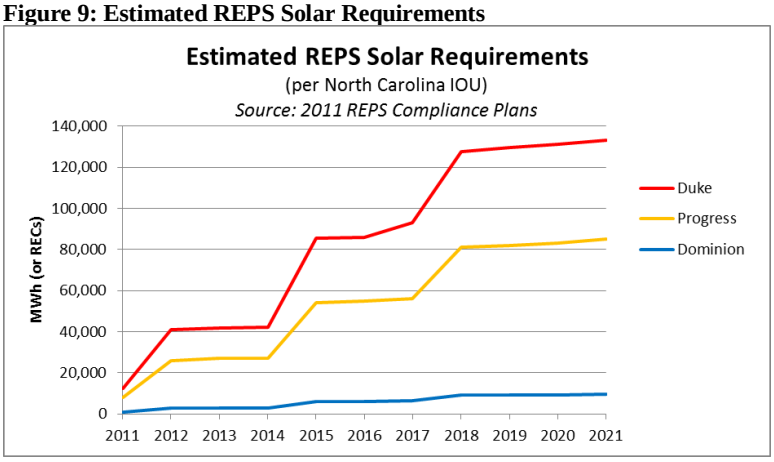
compliance goals gradually increase over time leading up to the required goal in 2021 for IOUs and 2018 for other utilities. In addition, energy efficiency is permitted to make up a portion of the compliance and electricity demand reduction up to 100% of the compliance. Utilities comply with these requirements by generating their own renewable energy or acquiring RECs associated with the generation from eligible energy and efficiency sources.

North Carolina also became the 6th state to require a solar carve out in an RPS, with IOUs required to supply 0.2% of the generation mix from solar technologies (including PV and solar water heating) by 2021. Other carve outs in the REPS include 0.2% from swine waste and 900,000 MWh from poultry waste by 2021. The REPS' requirements are detailed in Figure 8. The corresponding solar requirements per IOU are shown in Figure 9.

Figure 8: North Carolina REPS Compliance Schedule for IOUs

North Carolina REPS Compliance Schedule for IOUs		
	% of previous year's retail sales	% from solar
2010		0.02%
2012	3%	0.07%
2015	6%	0.14%
2018	10%	0.20%
2021	12.5%	0.20%

Figure 9: Estimated REPS Solar Requirements



Regarding small PV systems, an RPS in general creates a market for the energy it generates and the associated RECs. However, if the RPS requirements, especially the solar carve outs (if applicable), are not set high enough, IOU demand for SRECs can be insufficient. Apart from Progress' SunSense program, IOU residential customers in North Carolina currently are not provided enough financially attractive options for selling their RECs to their utilities.
Duke is North Carolina's largest IOU and has the most retail electricity sales among all other utilities in the state. Despite consequently having the largest REPS solar requirements (Figure 9), Duke has complied with the solar set aside mostly in the form of its company-owned $10MW_{DC}$ distributed generation program[10] and acquiring RECs from larger PPAs (including a $15.5MW_{AC}$ solar farm), solar water heating systems in the state, and PV systems operating outside the state. As NCSEA Counsel Kurt Olson revealed when cross-examining a Duke Energy witness in 2011[11], Duke has accumulated sufficient RECs and contracts to meet the REPS solar carve outs through 2018. In other words, no additional solar generation or SRECs need to be actively pursued by Duke. Overall, Duke does not offer to purchase SRECs from individual small PV owners.

Progress, on the other hand, has made available solar incentives for residential systems between $2kW_{AC}$ and $10kW_{AC}$, inclusive, and commercial systems between $11kW_{DC}$ and $500kW_{DC}$, inclusive. In 2011, Progress' SunSense[12] residential PV rebate program began offering Progress customers an upfront rebate of $\$1000/kW_{AC}$ plus a five-year monthly bill credit of $\$4.50/kW_{AC}$ for small, new roof-mounted PV systems in exchange for customers' RECs for the first five years. The program capacity limit is $1MW_{AC}$, with the similar commercial program limit set at $5MW_{DC}$ (which began in July 2009). For Progress, the residential and commercial SunSense programs are planned to be the major source of its solar requirement compliance with the REPS. As such, its residential program will demand SRECs from $5MW_{AC}$—which comes out to a range of 500 to 2,500 customers—until December 31, 2015[13].

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[10] Duke Energy Carolinas, LLC. (2011 September). *2011 Renewable Energy and Energy Efficiency Portfolio Standard Compliance Plan*.
[11] Urlaub, Ivan. (2011 June 14). *Duke Energy Admits: No More Solar Needed In NC for REPS*. NCSEA News. Retrieved from www.energync.org.
[12] Progress Energy Carolinas, Inc. (2010). *Residential Service (Experimental) Sunsense Solar Rebate Rider SSR-1*.
[13] North Carolina Utilities Commission. (2010 November). *Docket No. E-2, Sub 979*.

Dominion, despite being the largest retailer of electricity in Virginia, serves very few retail customers in North Carolina compared to Duke and Progress. Unfortunately, in complying with its 2010 solar carve out requirement of the REPS, Dominion stated purchasing all out-of-state RECs. Furthermore, as Figure 9 shows, Dominion's solar carve out is relatively minimal and may not be enough to move the IOU to offer incentives for RECs from small PVs in its relatively small service territory in northeastern North Carolina.

Despite the failed efforts of the 2011 Solar Jobs Bill (S473/H495) to double the REPS solar carve out to 0.4% by 2018[14], North Carolina's IOUs are in a position to comply without additional significant amounts of solar energy beyond their current investments and SREC contracts. Unless utilities decide to comply with the general REPS requirement from more PV systems voluntarily, small PV customers in North Carolina may not be offered any IOU solar incentives beyond Progress' SunSense program. *Note: North Carolinians also have the opportunity to sell their SRECs to out-of-state utilities looking to comply with their own state RPS. Pennsylvania (only for Dominion North Carolina customers) and Washington, D.C., were available markets[15]. Unfortunately, in 2011, Washington, D.C. closed off its SREC market to out-of-state suppliers[16].*

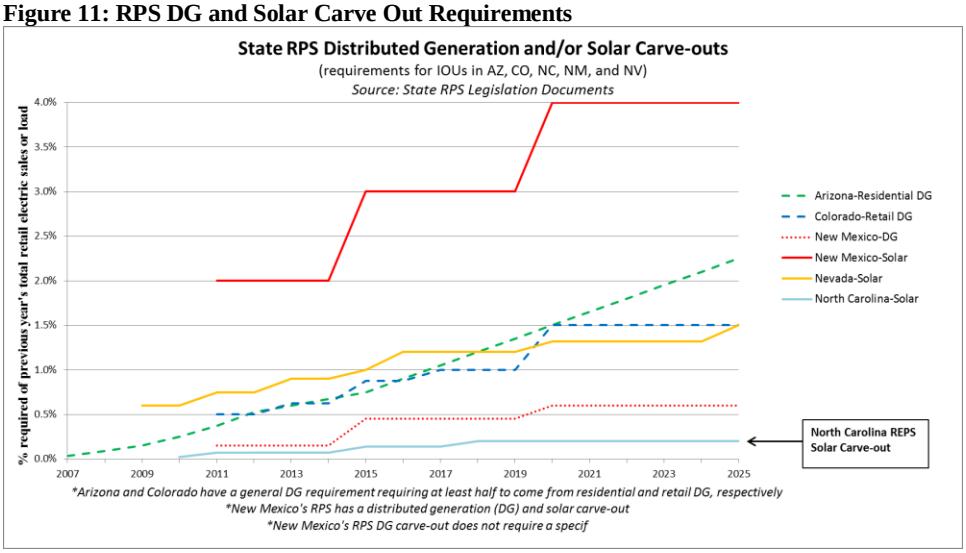
Compared to other states analyzed in this report, North Carolina's REPS is significantly less aggressive (Figure 10). Additionally, North Carolina's solar carve out compares fairly poorly to these states in terms of percentages (Figure 11).

Figure 10: RPS Requirements for IOUs

Overall RPS Requirement for IOUs	
Colorado	30% by 2020
Nevada	25% by 2025
New Mexico	20% by 2020
Arizona	15% by 2025
North Carolina	12.5% by 2021

[14] The Solar Jobs Bill, NC-S. 473. (Session 2011).
[15] SRECTrade. (2011 July 12). *DC Closes Borders to Out-of-State Solar Systems.* SREC Trade blog. Retrieved from www.SRECtrade.com.
[16] Ghandi, Natwar M. (2011 May 25). *Memorandum to the Honorable Kwame R. Brown: Fiscal Impact Statement-"Distributed Generation Amendment Act of 2011".* Government of the District of Columbia Office of the Chief Financial Officer.

Figure 11: RPS DG and Solar Carve Out Requirements



Property Tax Abatement

In 2008, North Carolina began exempting 80% of the appraised value of PV systems from property tax. However, if a residential PV system is not depreciated and is not recognizing income, the property is considered non-business personal property and is excluded from any property tax[17]. This means for residential PV owners net metering, including through Progress' SunSense program, the 80% tax abatement is unnecessary because they are fully exempt from property tax. On the other hand, for residential PV owners contracted with NC GreenPower or a buy-all sell-all PPA, the 80% tax abatement is valuable because they are required to pay property tax.

Sales Tax Exemption

Currently, North Carolina does not exempt PV systems from sales tax. However, for residential PV customers selling 100% of their electricity to an electric power company for resale to other customers (i.e., PPA or NC GreenPower), they are exempt from state and local sales and use taxes and are subject instead to a "privilege tax" (Article 5F. Manufacturing Fuel and Certain Machinery and Equipment[18]) of 1% for a maximum tax of $80 per article[19]. For residential PV customers net metering or consuming 100% of their generated electricity on-site, they are liable

[17] Baker, David B. (2011 February 15). *Memorandum to County Assessors: Solar Energy Electric Systems*. North Carolina Department of Revenue.
[18] North Carolina General Statutes §105-187.51. Taxation: Subchapter: I. Levy of Taxes: Article 5F. Certain Machinery and Equipment. (2007).
[19] Huie, Y. Canaan. (2012 March 7). PowerPoint presentation of *Taxation of Solar Electricity Equipment*. North Carolina Department of Revenue.

for a state sales and use tax of 4.75% and local sales and use tax of 2% or 2.25% (based on the county), for a combined 6.75% or 7% tax.

State Policies for Additional Financing Options

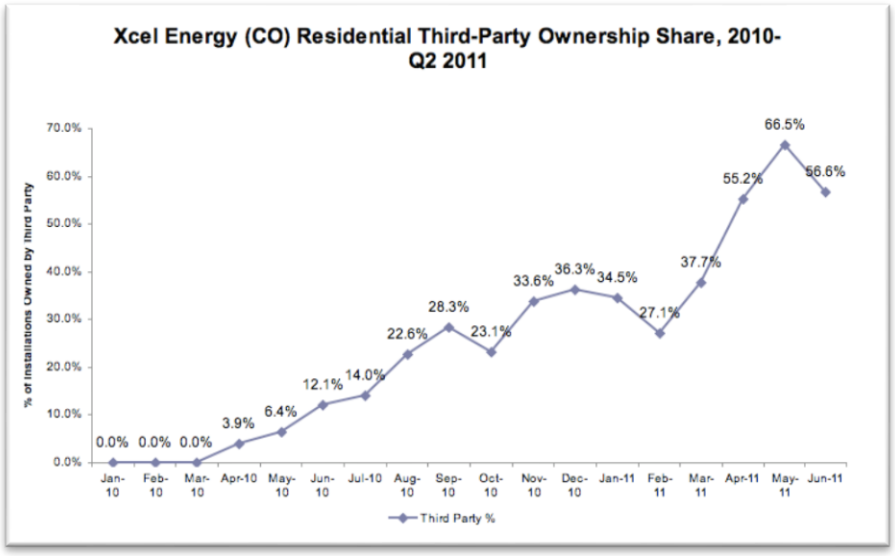
Third-Party Power Purchase Agreement

A third-party power purchase agreement (PPA), also known as a third-party sale of electricity, addresses the issues of PV systems' high upfront costs and relatively long payback period (if at all). In a third-party PPA, a developer (not the utility or customer) owns and installs a PV system on a customer's property and sells the generated electricity directly to the customer. This model, ideally, would allow customers who cannot or do not want to pay for the high upfront costs of owning a PV system to still consume PV-generated electricity and at rates lower than their utility's retail electricity price. The Q1 2012 *U.S. Solar Market Insight Report* claims that the residential trend in the United States is to choose a third-party PPA model or lease[20] over direct ownership of a PV system. This trend is evident with Colorado's largest IOU, Xcel Energy, which has seen the share of third-party owned PV systems rise to more than half of total residential PV customers in April 2011 (Figure 12).

In North Carolina, third-party owned generation is by definition not excluded as a regulated public utility and therefore faces regulatory barriers[21]. Despite the efforts in 2011 of House Bill 906[22] to study the feasibility and desirability of third party sales and Senate Bill 694[23] to define that third-party owned generation is not a regulated public utility, both bills failed to make it to the floor for a vote.

[20] A solar lease is different from a third-party PPA in that the customer does not pay for the electricity in kWh generated by the PV system. Rather, the customer pays the provider only to lease the system (usually through monthly payments). In a solar lease, the provider generally installs the system cost-free for the customer.
[21] North Carolina General Statutes §62-3. Public Utilities Act: Definitions. (1963).
[22] LCR to Study Third-Party Sale of Electricity, NC-H. 906 . (Session 2011).
[23] Energy Independence & Job Creation in NC., NC-S. 694. (Session 2011).

Figure 12: Xcel Energy (CO) Residential Third-Party Ownership Share
Source: GTM Research's U.S. Solar Market Insights Report Q2 2011



Meter Aggregation and Community Solar

Currently, North Carolina does not allow meter aggregation or community solar. Meter aggregation allows properties, such as farms, with multiple meters to combine (or "aggregate") accounts for net metering across one or more property boundary. Community solar allows customers who have difficulty physically installing a PV system on their property to invest in off-site PV systems, earn net metering credits, and participate in incentive programs. Examples of such difficulties include lack of sunlight access or a landlord not allowing solar installation on the property. Meter aggregation and community solar would give North Carolinians more options to make solar energy a viable and cost-effective investment.

PACE Financing

Property Assessed Clean Energy (PACE) financing is a way for property owners to borrow money to pay for eligible clean energy improvements. In areas with PACE legislation in place, municipal governments offer a certain bond to investors and then lend the money to property owners for clean energy improvements. The borrower repays the loan over a specified term, usually 15 or 20 years, via a special assessment on the borrower's property tax bill. In August 2009, North Carolina authorized[24] counties and cities to certain financing mechanisms for

[24] General Assembly of North Carolina. Session Law 2009-525. Senate Bill 97.

eligible clean energy technologies, including PACE. However, the Federal Housing Financing Agency (FHFA) issued a statement[25] in July 2010 concerning the senior lien status associated with most PACE programs. In response, most local PACE programs in North Carolina have been suspended.

[25] Federal Housing Finance Agency. (2010 July 6) *FHFA Statement on Certain Energy Retrofit Loan Programs*.

Key Federal Policies

Public Utilities Regulatory Policies Act (1978; amended 2005, 2007)

PURPA, passed in 1978 by the U.S. Congress, obliges states to require all electric utilities to offer to sell electric energy to and purchase electric energy from qualifying small power production facilities 80MW or less, which includes small PV systems. The rate at which utilities must purchase energy is at their "incremental cost of alternative electric energy", or more commonly referred to as "avoided costs". These avoided costs are determined for each electric utility by how much it would cost for the utility to generate or purchase from another source, such as a large coal-fired power plant.

The Energy Policy Act of 2005 (EPACT 2005) amended sections 1251-1254 of PURPA by adding that "States-must-consider" requiring electric utilities to make available upon request net metering and interconnection services to any electric consumer the electric utility serves. As of July 2012, 40 states and Washington, D.C. have adopted a state net metering policy[26]. As of May 2012, 32 States and Washington, D.C. have adopted a state interconnection standard[27].

Federal Investment Tax Credit (2006; extended 2008; amended 2009)

The federal investment tax credit was established by EPACT 2005, extended to expire on 12/31/2016 by The Energy Improvement and Extension Act of 2008, and amended to remove the maximum credit amount for all eligible technologies by The American Recovery and Reinvestment Act of 2009.

For all eligible technologies, including PV systems, a taxpayer can claim a tax credit of 30% of installed costs (less any state rebates) with no individual maximum credit limit. The credit can be taken all at once unless the credit exceeds the tax liability for that year, in which the excess amount would be carried forward to the next taxable year.

[26] DSIRE. (2012 December). Summary map of *Net Metering*. Retrieved from www.dsireusa.org.
[27] DSIRE. (2012 November). Summary map of *Interconnection Policies*. Retrieved from www.dsire.org.

PART II. MATERIALS AND METHODS

Part II of this report builds off the policies and incentives researched in Part I in order to perform a financial analysis of small PV ownership for the average Duke and Progress residential customer. Although all of the policies and incentives reviewed in Part I were not modeled in their entirety (or at all) in Part II, they were reviewed because they were considered by the author to be significantly impactful for small PV ownership or for potentially effective non-ownership alternatives, as further discussed in the Discussion section of this report. The policies and incentives chosen to be analyzed in Part II, thus, were perceived to be impactful for the financial attractiveness on small PV ownership by the author of this study.

Excel Model

The basic format of the interactive Excel cash flow model includes an input sheet, cash flow output sheet (see Appendix D and Appendix E for the reference cases' cash flows), and various sheets for calculations for monthly bills and electricity generation—all of which are linked together through formulas. As the user alters the variable inputs, the cash flow values and investment decision calculations (i.e., NPV, IRR, net benefits) update automatically. The cash flow sheet is of additional value beyond this report in that it allows the user to identify specific costs and benefits, their values, and in what year they are accrued. Thus, this model is intended to be used for analyses within and beyond the scope of this report.

The model incorporates the energy generation value outputs and basic cash flow setup from the National Renewable Energy Laboratory's System Advisor Model (SAM) (refer to Appendix C for intermediate steps taken with SAM). Although many aspects and tools used from SAM were crucial, SAM did not provide the level of detail needed for specific purposes of this study, including the list below. *Note that the required hourly system generations and load profiles from SAM were simply copy-pasted to this Excel model and linked to applicable cells—once this data is added, the Excel model works independently of SAM.*

- Net excess generation effects from net metering
- Effects from net metering under a TOU demand tariff
- Distribution of the state renewable energy tax credit. *Note: SAM only allows the user to take the entire credit at the end of the first project year rather than equal installments over five years (as this study does).*

- Changes in tariffs during the project's life. For example, a customer may need to switch to a TOU demand tariff from a flat-rate tariff for contract purposes.
- The interaction between tax credits and rebates. For example, since both the federal and state investment tax credits are taken *after* rebates are taken out of the total cost, SAM overestimates the tax credit amounts awarded.

Cash flows were used as a form of financial analysis because they provide a method of organizing a project's benefits, costs, and net cash flow per period, and more importantly, are conducive to calculating the net present value (NPV) of the project. All entries in this study's cash flows were in real dollars, on an accrual basis, and not accounting for inflation. A discount rate of 5.00% was used for the reference cases in this study. The investment rule primarily assessed was NPV, but was also accompanied by the internal rate of return (IRR) and net benefits (i.e., NPV at a 0% discount rate). *Note: Both the IRR and net benefits were only interpreted for individual projects, that is, they are not used to compare mutually exclusive projects.*

The cash flow format organized the benefits and costs over a 25 year project lifetime with Year 0 indicating the investment period, which is not discounted. The first calendar year of the project is referenced as 2013. The fixed inputs used for all cases are shown in Figure 13. While remaining conservative, each reference case and the scenario analyses reflect what this study decided to be the best financial option available. For example, since Progress' SunSense program is not available for Duke customers, the next best option for the Duke customer reference case was to contract with NC GreenPower. Also, with exception to SunSense and NC GreenPower, renewable energy credits (RECs) were assumed to be uncertain in terms of its selling price and demand overall for North Carolinians. Thus, in most cases, a 1-to-1 net metering—meaning 1kWh of generation displaces 1kWh of consumption regardless of when it was generated or consumed—was used despite having to surrender all associated RECs to the utility at no compensation (for further explanation of this, see Part I's Net Metering section).

Savings from deferred electricity consumption were entries for cash in in the cash flows and were calculated by taking the difference between a baseline bill (Line 3 in Appendix D and Appendix E) and the newly calculated bill. The baseline bill was calculated by multiplying the hourly load data by the chosen tariff rates, taking into account electric rate and demand charge

growth rates. Baseline bills were calculated using flat rates in all cases except when net metering under a TOU demand tariff. Since switching from a flat-rate tariff to a TOU demand tariff will result in differences in baseline bills, baseline bills were calculated and used depending on what tariff the case uses for that year. This method was used in order to focus only on the benefits attributable to the decision to invest in small PV systems and not on relative bills savings (or losses) based on tariff choices that can also be made independently of PV investments.

Figure 13: Fixed Inputs to Cash Flow Model

Fixed Inputs	Value	Notes	Source
Analysis Period (years)	25	Year 0 indicates the investment period and is not discounted	
Federal Marginal Tax Rate	28.00%	2012 bracket-Married, filing jointly: $142,700-$217,450	IRS
State Marginal Tax Rate	7.75%	2012 bracket-Married, filing jointly: >$100,000	NC Dep. of Revenue
Inflation Rate	0.00%	No inflation	
System Degradation	0.05%		NCSEA report
Fixed O&M Cost ($/kW$_{DC}$/year)	20	default value from SAM	SAM
Assessed Property Value Decline	0.04	=1/(project life); only applicable if property tax required	calculation
Loan Rate	7.75%		NCSEA report
Loan Term (years)	10	only applicable if there is a loan	NCSEA report
DC to AC Derate Factor	0.84		NCSEA report

Reference Cases

Two reference cases, one for Duke and the other for Progress, were made for the average residential customer investing in a 4kW$_{DC}$ PV system. The list below details the explanations for choosing three of the main inputs. For all other inputs not further explained, values were chosen conservatively and based on the judgment of the author of this study. See Appendix F for these values.

- 4kW$_{DC}$ system was chosen for the reference cases because it closely reflects the average size calculated from interconnection requests[28] reported from Duke and Progress from 2005 to 2012.
- $6.04/W$_{DC}$ as the installed cost for residential PV systems in 2013 (in North Carolina) was taken from NCSEA's *Levelized Cost of Solar Photovoltaics in North Carolina* report.
- A 0.10% annual compounding electric rate and demand charge growth reflects the results from EIA's Annual Energy Outlook 2012 reference case[29].

For the Progress customer reference case, the best option was to contract with the SunSense program (assumed to be available and offered to the customer) and then (after five years) elect to

[28] For all North Carolina IOUs, these reports can be found in NCUC's Docket No.E-100, Sub 101A.
[29] EIA Table Browser. (2012). Retrieved from http://www.eia.gov/oiaf/aeo/tablebrowser/.

net meter under a 1-to-1 kWh ratio (subsequently surrendering all associated RECs). Due to the SunSense program not being made available to Duke customers and Duke currently not offering to purchase RECs from small PV systems, the Duke customer reference case's best option was to use the guaranteed five-year contract with NC GreenPower and simultaneously contract with Duke for a buy-all sell-all power-purchase agreement (PPA). Unfortunately, this will require paying a property tax—using the 2012 property tax rates for Durham County and the City of Durham—for the first five years of the project as it is considered business personal property. Despite this additional tax, by entering into a PPA, this project then becomes eligible for the 1% privilege tax instead of the 7% sales tax for residents in Durham County (due to Article 5F, as explained in Part I). Similar to the Progress customer, the Duke customer will proceed with net metering under a 1-to-1 kWh ratio after Year 5.

Scenario Analysis

The first set of scenarios analyzes the effects of current incentives on the reference cases. The first scenario removes all incentives except the state and federal investment tax credits (ITC). It also uses net metering for the full project life under a 1-to-1 kWh ratio. The second scenario builds off the first scenario by further removing the state ITC. Finally, the third scenario builds off the two previous scenarios by further removing the federal ITC. The aim of these incremental scenarios is to analyze how effective these incentives are in making these projects more financially attractive and at the same time how financially unattractive these projects would be without them. The full set of variable inputs is included in Appendix F.

The second set of scenarios analyzes the hypothetical situations where North Carolina adopts the major policies, incentives, and climate locations existing (as of December 2012) by the other states examined in Part I of this study: Arizona, Colorado, New Mexico, Nevada (see Appendix F for specific values). In all scenarios, everything except the state ITC, sales tax policy, property tax policy, net metering policies, utility-provided incentives, and climate locations remain unchanged. This analysis continues to be from the perspective of the average Duke or Progress customer living in North Carolina and subject to electric rates in their respective IOU territory. The best financial options (chosen conservatively) are used for the largest investor-owned utility in each respective state and openly available on a relatively large scale. For example, Nevada's

two largest IOUs provide solar power rebates to their customers but only for a very limited number of customers and in such manner are excluded in this analysis. In terms of the reference cases, the first scenario only changes certain policies and incentives as used in another state, keeping the climate unchanged (i.e., Raleigh, NC). The second scenario uses the same inputs from the first scenario, but changes the climate location for the respective state policies and incentives. Climate locations only affect the hourly generation for the PV system and are outputs from SAM.

Note, however, that the second set of scenarios does not calculate the financial attractiveness of PV ownership from the perspective of these other four states' IOU customers. For instance, this study does not account for these other states' electric rates (and potential growth), residential electric loads, potential programs like NC GreenPower, and other incentives not analyzed that may significantly impact the NPV. In short, no conclusions such as stating that projects in North Carolina are financially more attractive than similar projects in Arizona, Colorado, and Nevada can be made by this study. This analysis, however, it is meant to broadly compare the amount and effectiveness of state policies and incentives in the context of the reference cases, and to analyze how much of an effect climate has on these projects. A final note of caution is to take these scenarios within the context of the current time (end of 2012), that is, the set of policies and incentives being offered now in these states may be significantly different than even a few years ago.

Sensitivity Analysis

The variable inputs that the sensitivity analysis includes are shown in Figure 14. For the most part, only one variable at a time was changed in the context of the reference cases. The variables chosen to be analyzed were assumed to be the most impactful in terms of the reference cases. Many of these variables are not policies or incentives, such as system capacity and the discount rate, yet may significantly impact the NPV of the reference cases if inputted with a range of values.

An additional non-financial analysis is included in this study to investigate how much net excess generation is surrendered to the utility by changing only system capacity. This is a sensitivity

analysis in the context of when both IOU customers elect to net meter under a TOU demand tariff. All other inputs are the same as the reference case, though many do not impact the results since surrendered net excess generation is not impacted by financial inputs.

Figure 14: Sensitivity Analysis Variable Inputs for Cash Flow Model

Sensitivity Analysis Variable Inputs	
System Capacity (kW_{DC})	0.5-10 (0.5 increments)
System Installed Cost per Capacity ($/$W_{DC}$)	6.04, 5.65, 5.28, 4.94, 4.63, 4.35, 4.08, 3.84, 3.45, 2.53
Real Discount Rate	0%, 2.5%, 5%, 7.5%, 10%
Property Tax Assessed %	0%, 20%, 100%
Debt Fraction (Loan)	0%, 25%, 50%, 75%, 100%
Utility Capacity-Based Incentive ($/$W_{DC}$)	0, 0.50, 1.00, 1.50, 2.00
Utility Production-Based Incentive ($/kWh)	0, 0.50, 1.00, 1.50, 2.00
Utility Production-Based Incentive (years)	5, 10, 15
Net Metering	TOU, 1to1
Electricity Rate & Demand Charge Growth Factor per year	0.998, 0.999, 1, 1.001, 1.002, 1.011

PART II. FINANCIAL ANALYSIS RESULTS

Note: The full set of results is presented in Appendix G and Appendix H. For the full cash flow of the reference cases, view Appendix D and Appendix E.

As a conceptual review, Part II of this study assessed the current status of small PV systems for Duke and Progress customers based on financial measures. Factors, such as the policies and incentives described in Part I, all impact the financial outcome of investing in small PV for Duke and Progress customers. Part II, thus, quantifies how they financially impact individual projects, investigated through reference cases, scenario analyses, and sensitivity analyses.

The main method of this analysis uses an interactive Excel-based cash flow model developed by the author of this report. By quantifying the benefits and costs of the investment and the period (i.e., year) they are accrued, the NPV, IRR, and net benefits can be outputted for assessment. If a project yields of NPV of $0 or higher, the project is considered to be a financially attractive—the investor should invest in the PV system. If the NPV is negative, then it is not a financially attractive investment. The IRR and net benefits are also assessed to provide additional insight beyond the NPV.

Reference Cases

The reference cases resulted in an NPV of -$8,111 and -$6,254 for the Duke and Progress customer, respectively. Additionally, both the net benefits and IRR were negative as well, the latter being -5.0% and -3.3% for the Duke and Progress customer, respectively. Overall, with a negative NPV for both IOU customers, the reference cases result in an unfavorable investment opportunity.

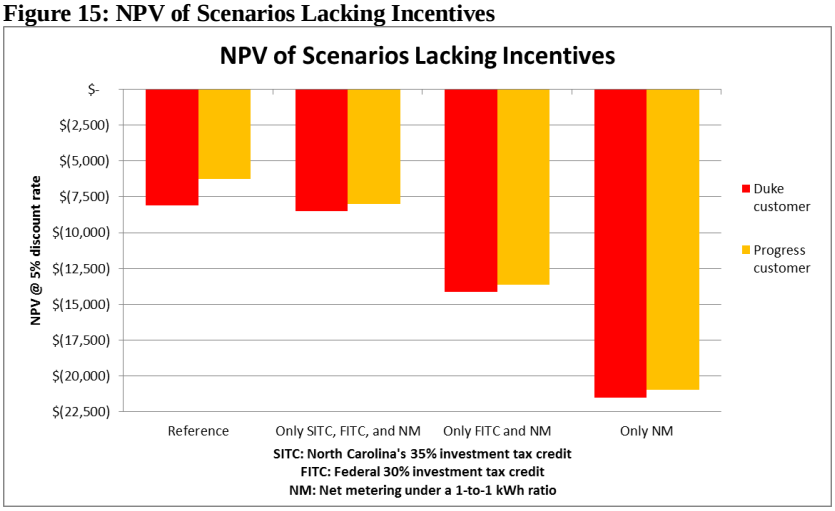
In addition to these results, there were two key takeaways from the reference cases. First, the SunSense program available to Progress customers significantly impacted the NPV of the project when compared to the next best alternative, which in this study was contracting with NC GreenPower. Second, the calculated load profiles and electric rates favor the Progress customer more than the Duke customer, that is, the incentives and energy savings from the PV system is of more value in the Progress customer's reference case.

Scenario Analysis

As expected, the scenarios incrementally removing incentives resulted in decreasing NPVs (see Figure 15). The first scenario removing the SunSense and NC GreenPower incentives and switching to a 1-to-1 kWh ratio for net metering yielded interesting results. The change for the Progress customer under the SunSense program experienced a larger drop (a $1,744 decrease) in NPV compared to the Duke customer contracted with NC GreenPower (a $388 decrease). From this difference, one could conclude that the SunSense program is more effective in increasing the NPV compared to NC GreenPower, especially with the low premiums offered as of December 2012. Back when NC GreenPower offered $0.18/kWh, it undoubtedly would have impacted the NPV much more significantly than it does now. The minor NPV impact from NC Greenpower on the reference case can also be attributed to the $490 in additional administrative charges from the PPA and the $291 paid in property taxes over five years for the Duke reference case.

This first set of scenarios also present how effective the state and federal ITCs are to the reference cases' NPVs. The lack of the state ITC (incrementally from the previous scenario) drops the NPV of both projects by more than $5,600, and the removal of the federal ITC (again, incrementally from the previous scenario removing the state ITC) drops the NPV of both projects by more than $7,300. The reason the state's 35% ITC alters the NPV less than the federal 30% ITC is due to the interaction between the state ITC, state marginal income taxes, and federal marginal income taxes. As Part I of this study explains, the state 35% ITC is actually a net 25.2% reduction in total costs after income tax interactions are accounted for (for the reference cases). Nonetheless, the ITCs are critical and have a much more significant impact than SunSense and NC GreenPower have.

Figure 15: NPV of Scenarios Lacking Incentives



The second set of scenarios analyzed hypothetical situations where the reference cases could use the major policies, incentives, and climates existing (as of December 2012) in Arizona, Colorado, New Mexico, and Nevada (Figure 16 and Figure 17). Based on the results of these scenarios, it can be broadly concluded that North Carolina residential customers with Duke or Progress are currently being offered incentives that together result in projects having a higher NPV than if other major policies from these other four states were implemented (holding all inputs constant, including climate and rate schedules). Once respective climates are included, the reference cases' NPVs still are higher than the other scenarios with the exception of New Mexico. This shows that despite negative NPVs from the reference cases, small PV owners are being offered relatively effective incentives compared to these other states' major incentives, even when climate is considered.

Another point to consider from this second set of scenarios is the effect climate has on the NPV. To no surprise, the other four states in these analyses have climates that contribute to more benefits compared to North Carolina's climate, holding all inputs constant. New Mexico's (i.e., Albuquerque's) climate, in fact, yields roughly a $3,000 increase in NPV beyond North Carolina's (i.e., Raleigh's) climate from both the Duke and Progress reference cases.

Figure 16: Scenario Analysis of Duke Case

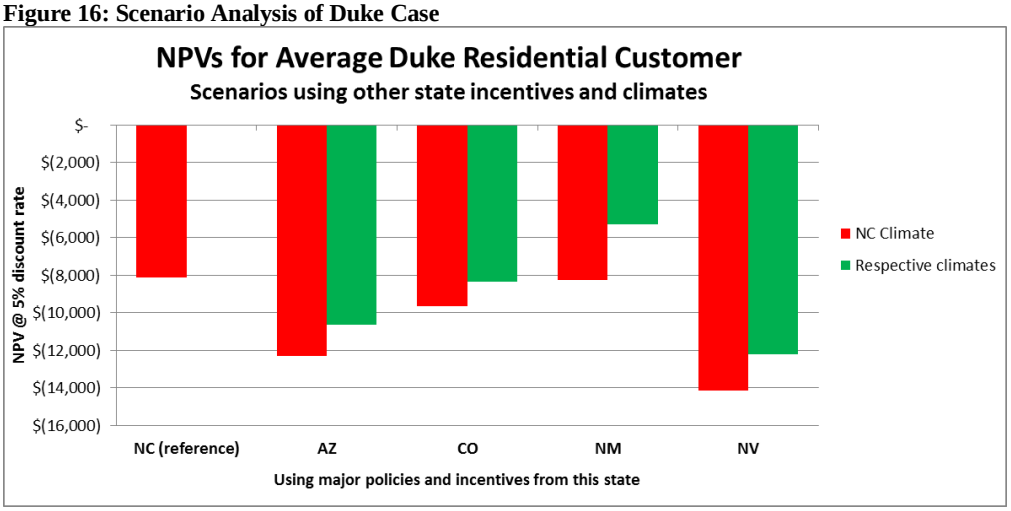
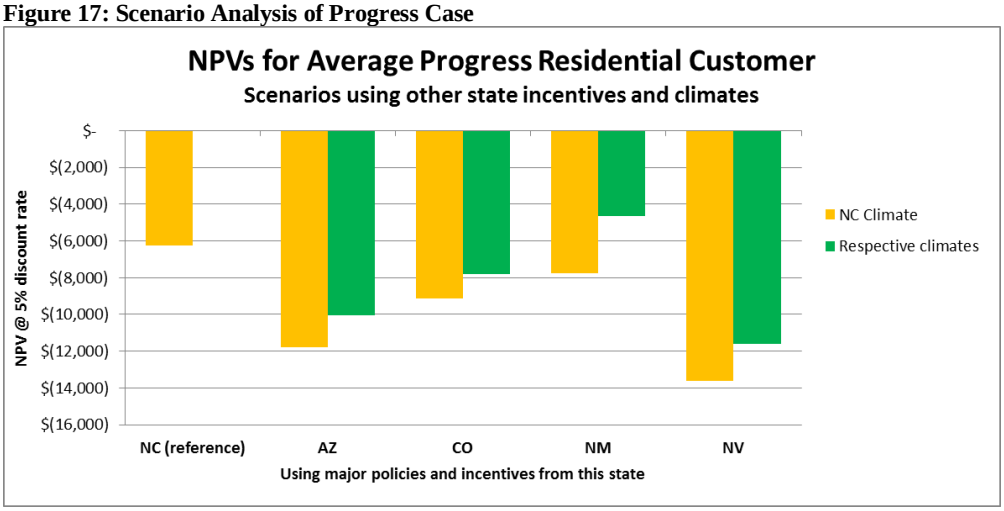


Figure 17: Scenario Analysis of Progress Case



Sensitivity Analysis

System Capacity

The change in NPVs from different system capacities[30] from 0.5 to 10 kW_{DC} were examined in increments of 0.5 kW_{DC}, as Figure 18 shows. For both reference cases, certain incentives were altered where system capacities were not eligible. For instance, the Progress customer is no longer eligible for the SunSense incentive below capacities of 2.5 kW_{DC} (i.e., the lower limit is 2 kW_{AC}) and above 6 kW_{DC} (system capacity in kW_{AC} cannot exceed annual peak demand, which is 5.1 kW). The Duke customer is eligible for the five-year NC GreenPower contract from 0.5

[30] One limitation to consider is that installed costs are kept constant for sizes 0.5 to 10 kW_{DC}. This was done in this study for simplicity and to avoid further assumptions.

kW_{DC} to 5.5 kW_{DC} (the upper limit is 5 kW_{AC}). It is important to note that for both reference cases, the system capacity is not technically allowed to go beyond 6 kW_{DC} due to the net metering rule in which the size must not exceed annual peak demand. Keeping that in mind, the analysis still included capacities of 6 to 10 kW_{DC} using net metering under a 1-to-1 kWh ratio and excluded any benefits from selling RECs.

The results of this analysis are valuable if one looks beyond the glaring negative NPVs and IRRs. That being said, one should not invest (from a financial point-of-view) in these specific projects regardless of this given range of systems or resulting IRRs. From the perspective of both reference cases, the highest IRRs are yielded when the system is eligible for SunSense or NC GreenPower (for the Progress and Duke customer, respectively) (Figure 19). What is also interesting is that once the system capacity surpasses the eligible range, the IRR continues to decrease rather than remain relatively constant. This is due to the limit of $10,500 for the state ITC. Once that limit is reached, the return on investment is less in relation to the capital costs. Additionally, the Duke customer increases nearly 2% in IRR from 0.5 to 4.5 kW_{DC}. This is due to the property taxes paid and fixed administrative charges (i.e., fixed costs), meaning the current benefits of NC GreenPower may not be worth the additional costs in the context of smaller systems and the reference case.

Figure 18: Sensitivity Analysis of System Capacity (NPV)

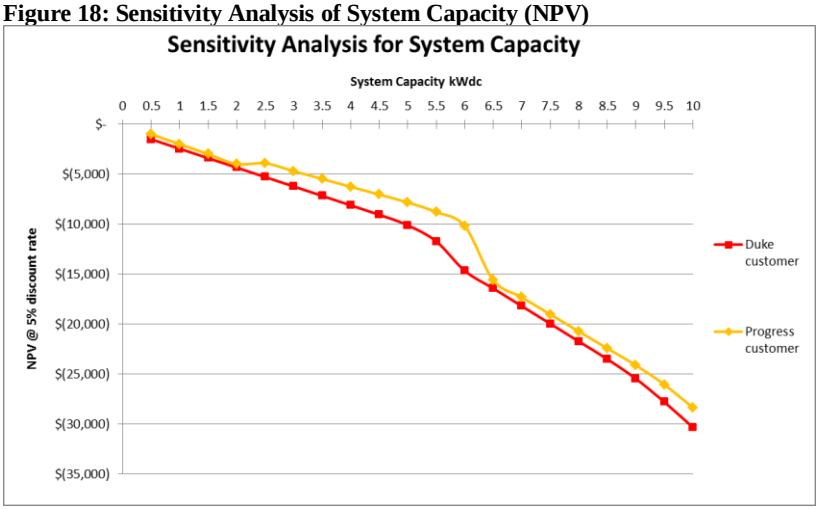
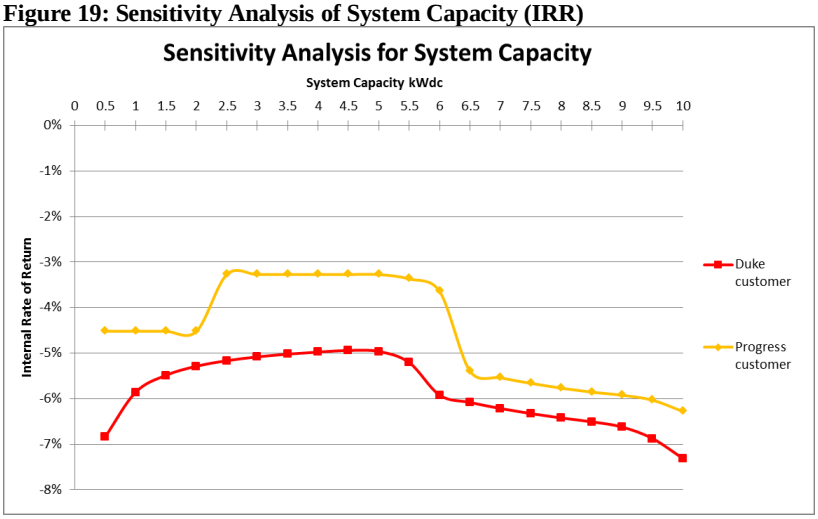


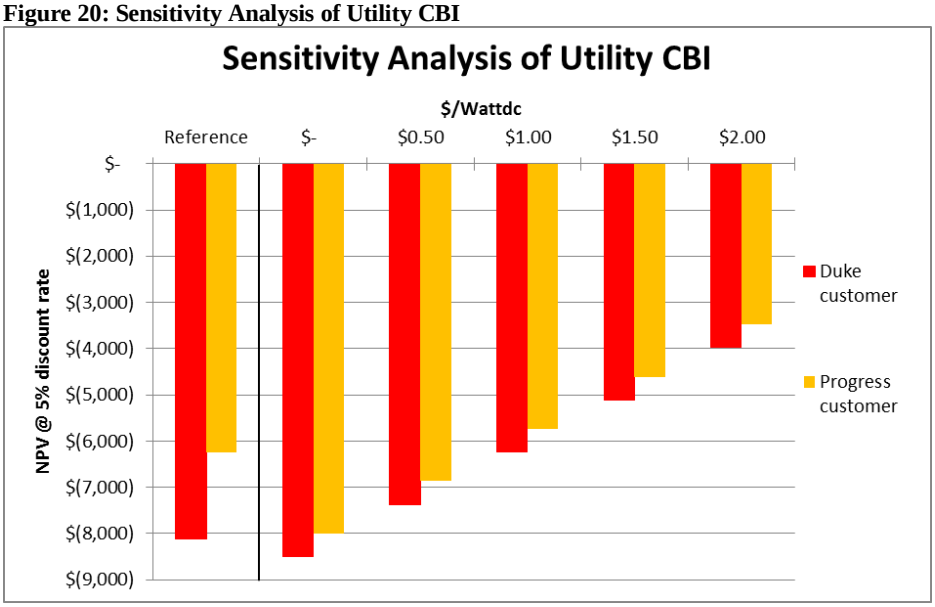
Figure 19: Sensitivity Analysis of System Capacity (IRR)



Utility Capacity-Based Incentives

Utility capacity-based incentives (CBI) were initially only incorporated for the Progress customer reference case, which contracts with SunSense ($1/W$_{AC}$ = $0.84/W$_{DC}$ for the reference case). However, in order to analyze the effects of a range of CBIs on projects, the reference cases were altered to net metering under a 1-to-1 kWh ratio and with no additional benefits for RECs (i.e., no NC GreenPower or SunSense). A range from $0 to $2 per W$_{DC}$ in $0.50 increments was used. The results, as shown in Figure 20, show that a CBI of $0.50/W$_{DC}$ results in an NPV $742 higher for the Duke customer compared to its reference case. With a CBI of $1/W$_{DC}$, the NPV is $516 higher for the Progress customer compared to its reference case. The combination of 1-to-1 kWh ratio net metering and a CBI can be an effective option in the context of the reference cases, especially for Duke residential customers facing a declining NC GreenPower premium.

Figure 20: Sensitivity Analysis of Utility CBI

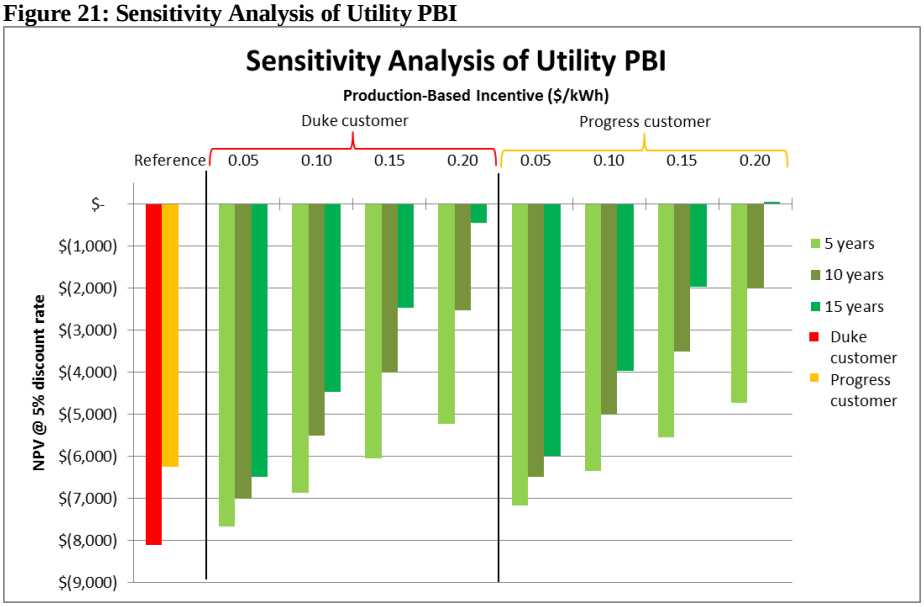


Utility Production-Based Incentives

Utility production-based incentives (PBI) were not initially incorporated in either of the two reference cases. Similar to the sensitivity analysis of utility CBIs, the analysis of PBIs alter the reference cases to net meter under a 1-to-1 kWh ratio and with no additional benefits for RECs. PBIs are calculated as income from selling RECs and do not include the associated energy generation, that is, the customer still benefits from net metering in addition to selling RECs. PBI ranges used were $0.05 to $0.20 per kWh (in $0.05 increments) with each being offered for 5, 10, and 15 years, for a total of 24 NPV results (4 prices x 3 time durations x 2 utility providers).

There are a few takeaways from the results to consider, as made evident in Figure 21. First, all price-time duration combinations resulted in a higher NPV for the Duke customer compared to its reference case. Again, this alludes to the diminishing benefits of NC GreenPower at its current premium and requirement to enter a PPA. However, if the customer is allowed to net meter under a 1-to-1 kWh ratio and still earn the NC GreenPower incentive (i.e., $0.08 PBI for 5 years), the NPV can be increased by around $1,000, holding all inputs constant. Second, in the most generous case, a PBI of $0.20/kWh for 15 years, the NPVs are -$435 and $48 for the Duke and Progress customer, respectively. The latter, $48, would make that specific project financially attractive and worth investing in for all discount rates 5% or smaller.

Figure 21: Sensitivity Analysis of Utility PBI



Net Metering Policy

The reference cases were altered by removing all benefits from selling RECs and implementing net metering under one tariff, either TOU or flat rate (i.e., 1-to-1 kWh ratio), for the entire project life. This analysis, thus, is only focused on the benefits from net metering under each tariff. Under their respective TOU demand tariff, the Duke customer's NPV was -$11,177 and the Progress customer's NPV was -$10,966. Under their respective flat rate tariff, the Duke customer's NPV is -$8,499 and the Progress customer's NPV is -$7,998. This was an NPV increase of $2,678 and $2,968 for the Duke and Progress customer, respectively.

Based on the methods of this analysis[31], net metering under a flat rate is significantly better for the projects' NPVs. By limiting customers to net metering under a TOU demand tariff with REC ownership or under a different tariff without REC ownership drastically limits the full financial potential of small PV ownership.

[31] These results can be interpreted in different ways based on the methods for calculating electric bill savings, as explained in the Materials & Methods section of this report.

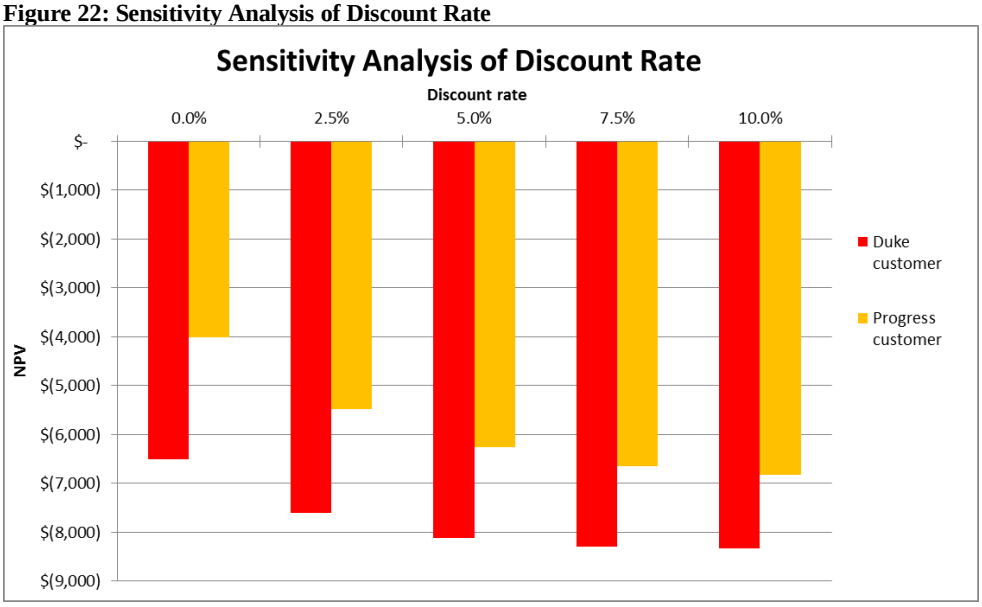
Property Tax

Property tax was only applicable for the Duke customer reference case, which contracts with NC GreenPower and Duke for a five-year PPA. The range of values analyzed was 0%, 20%, and 100% assessed percentages. At 100% the NPV was -$8,785. This is more than a $600 decrease in NPV compared to the reference case's NPV, which is at 20% (i.e., with the 80% tax abatement). Furthermore, at 0% (i.e., no property tax assessed), the NPV is -$7,943, roughly a $150 increase compared to the reference case's NPV. Despite these rather minimal effects, the difference between 100% and 0% assessed percentages can still contribute to more than a $750 difference in NPV in the context of the reference case.

Discount Rate

Both the reference cases used a 5% discount rate. 0%, 2.5%, 5%, 7.5%, and 10% discount rates were used for this analysis (Figure 22). Even at a 0% discount rate, the NPVs were still less than -$4,000 and -$6,000 for the Progress and Duke customer reference cases, respectively. If the reference cases had NPVs closer to $0, the discount rate would indeed make a much larger impact on decision making. However, it is important to note that since most of the larger costs and benefits are closer to the beginning of the project life than to the end, the difference between a 5% and 10% discount rate is not too significant—this decrease in NPV is only $266 and $574 for the Duke and Progress customer reference cases, respectively.

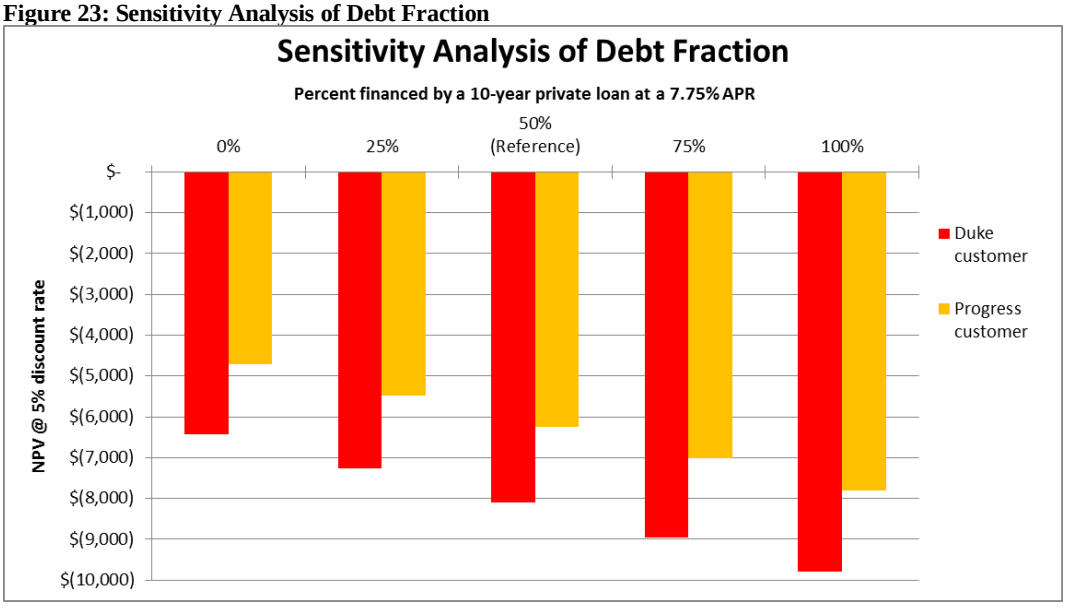
Figure 22: Sensitivity Analysis of Discount Rate



Debt Fraction

Both the reference cases were financed 50% by debt via a 10-year private loan at a 7.75% APR. Due to the high upfront costs of these projects, it is important to analyze how financing such projects affects the NPV. In terms of the Duke customer reference case, having a 0% debt fraction results in an NPV of -$6,430 (an increase of $1,682) and a 100% debt fraction results in an NPV of -$9,792 (a decrease of $1,682). In terms of the Progress customer reference case, having a 0% debt fraction results in an NPV of -$4,708 (an increase of $1,546) and a 100% debt fraction results in an NPV of -$7,799 (a decrease of $1,546). Note, however, that the Progress customer reference case at a 0% debt fraction results in a positive IRR (0.8%) yielding net benefits of $1,299 (see Appendix H). These results, as shown in Figure 23, show that the debt fraction can have a significant impact on the NPVs of the reference cases.

Figure 23: Sensitivity Analysis of Debt Fraction



Electric Rate and Demand Charge Growth Rate

The reference cases assumed a 0.10% increase per year of electric rates and demand charges. This value is the growth rate for end-use residential electricity prices ($2010/kWh) from 2010 to 2035 projected by EIA's Annual Energy Outlook (AEO) 2012 reference case. A range of growth rates from different AEO 2012 scenarios were used in this analysis (Figure 24). The results, as shown in Figure 25, show that within the range of the AEO 2012 scenarios' growth rates, electric rate and demand charge growth rates minimally impact the NPVs of the reference cases.

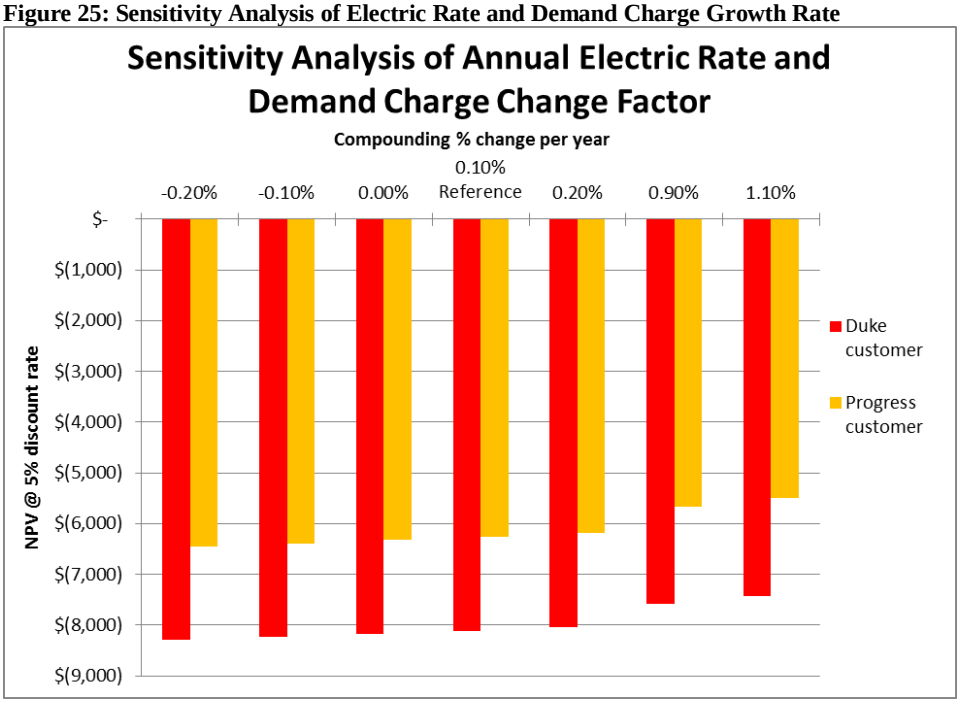
Compared to the reference cases, the NPVs using the highest growth rate (1.1%/year) only increase by $678 and $751 for the Duke and Progress customer, respectively. Similarly, the NPVs using the lowest growth rate (-0.2%/year) only decrease by $185 and $206 for the Duke and Progress customer, respectively. This minimal effect is largely due to the time-value of money. Even when retail prices become very high relative to current prices, the electric bill savings are so far in the future that they are discounted heavily and do not increase the NPV as much as it could if not discounted. Consider though, at the 1.1% growth rate, the net benefits of the Duke and Progress customer reference cases increase by $1,564 and $1,541, respectively.

In the context of the reference cases, this can be both a positive and negative finding from the perspective of the investor. On one hand, even if the growth rate is negative (within the range of the AEO 2012 scenarios), the project's NPV will not be drastically affected (in the context of these reference cases), meaning risk is low. On the other hand, even if growth rates are higher than expected, the project's NPV may not significantly increase, meaning the room for a significantly higher NPV based on these growth rates is not great.

Figure 24: EIA AEO 2012 Growth Rate Values

Growth Rate (2010-2035)	EIA AEO 2012 Scenario
-0.2%	Best Available Buildings Technology
-0.1%	High Technically Recoverable Resources
0.0%	High Estimated Ultimate Recovery
0.1%	Reference Case
0.2%	Low Estimated Ultimate Recovery
0.9%	$15 CO_2 Emission Fee
1.1%	$25 CO_2 Emission Fee

Figure 25: Sensitivity Analysis of Electric Rate and Demand Charge Growth Rate



Installed Cost per Watt

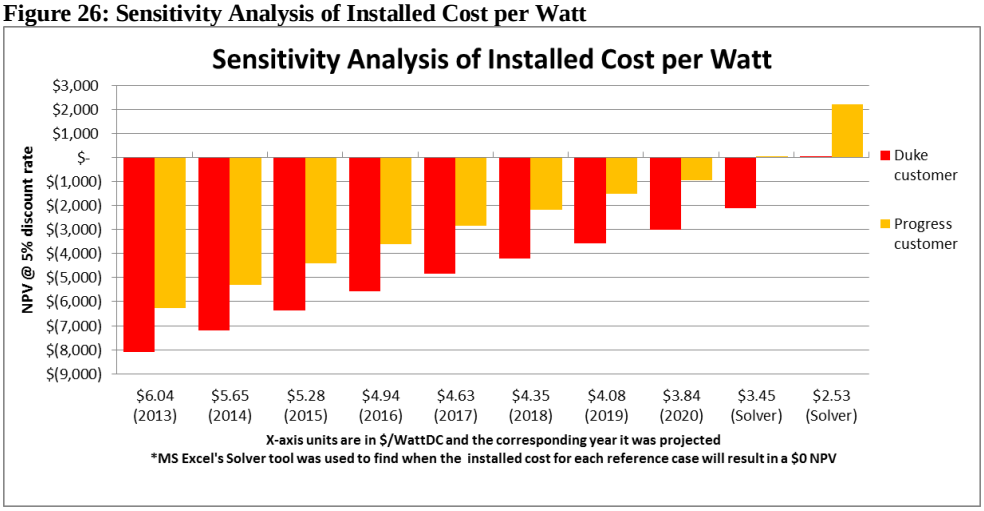
An installed cost of $6.04 per Watt was used for both reference cases as it reflects the projections for small systems (≤10kW) in North Carolina in 2013 from NCSEA's report. In order to further analyze the effects the installed cost can have on the NPV of the reference cases, projected costs from NCSEA's report were used up to 2020 (Figure 26). Since the NPVs still do not reach a minimum of $0 for either reference case, Excel's Solver tool was used to find what installed cost would result in a $0 NPV for both reference cases, holding all inputs constant. For the Progress customer this was $3.45/$W_{DC}$; for the Duke customer this was $2.53/$W_{DC}$.

This analysis looks at the reference cases using different installed costs and do not reflect NPV estimations for projects beginning in future years. In such manner, the years are only provided in Figure 26 for the purpose of indicating what year that specific installed cost was projected per NCSEA's report.

If the reference cases use an installed cost of $3.83/$W_{DC}$ (projected for 2020), they result in NPVs of -$3,028 and -$946 for the Duke and Progress customer, respectively. Thus, even at a 36% installed cost decrease, the reference cases still result in a negative NPV. This only further

strengthens this study's finding that the reference cases are currently financially unattractive investments. However, at an installed cost of $3.45/W$_{DC}$, only a 10% decrease from the 2020 projection, the Progress customer reference case results in a $0 NPV. In the context of the reference cases, a 43% and 58% decrease in the $6.04/W$_{DC}$ installed cost for the Progress and Duke customer, respectively, is necessary to make these projects financially attractive, holding all inputs constant. Also, when the installed cost is as low as $2.53/W$_{DC}$, the Progress customer reference case yields a $2,216 NPV with an IRR of 12.6%. Whether or not the installed cost per Watt will reach these levels is uncertain, yet they do appear to be in line with the projections from the NCSEA report and its assumption that costs do not drop below $1/W$_{DC}$.

Figure 26: Sensitivity Analysis of Installed Cost per Watt



Additional Analysis—Surrendered Net Excess Generation

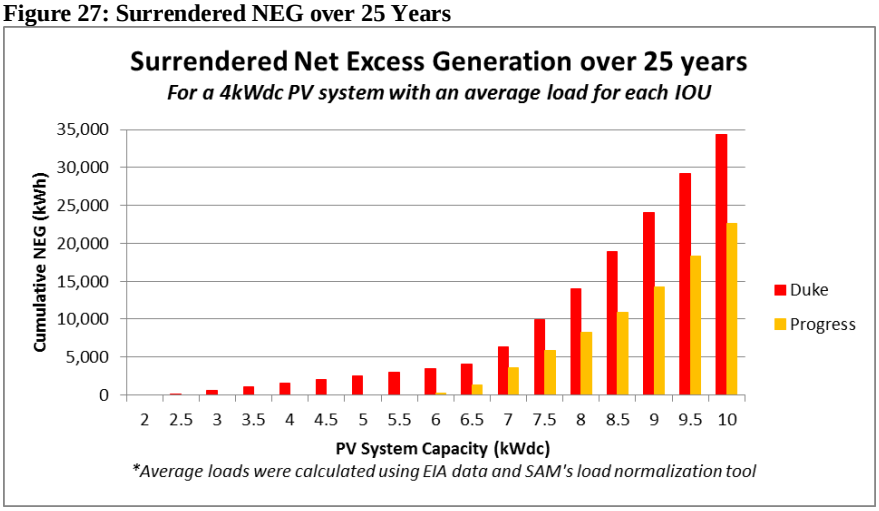
Both reference cases did not surrender any net excess generation (NEG) to their respective utilities. This non-financial analysis examined how different system capacities affect the surrendered NEG for the reference cases. The system capacities used were from 2kW$_{DC}$ to 10kW$_{DC}$ (in 0.5kW$_{DC}$ increments). Both reference cases were altered to net meter under a TOU demand tariff for the full project life. All other inputs were kept constant, including electric loads. Additionally, net metering system capacity limitations (i.e., must not exceed annual peak load) were ignored for purposes of this analysis.

As Figure 27 shows, the Duke customer reference case experiences larger amounts of surrendered NEG compared to the Progress customer reference case and starts losing NEG at smaller system capacities. This is primarily due to the load profile of the Duke customer reference case. First, the Duke customer has a smaller annual load and a smaller load in the month of May compared to the Progress customer—as a reminder, net metering under the TOU demand tariff requires all accumulated NEG to be surrendered on May 31st of each year. Second, the Duke customer has a much smaller on-peak load in the month of May in relation to the off-peak load, again compared to the Progress customer. This leads to the Duke customer having a large amount of NEG that cannot be used in the following month. The month of May, as it provides many hours of sunlight, is a detrimental time to surrender NEG.

The discrepancy between the Duke and Progress customer should not be emphasized extensively since much of it can be attributed to the load profile construction methods used in this study. However, the results of this analysis can present the sensitivity of load profiles and surrendered NEG. For certain load profiles, such as with the Duke customer reference case, net metering under the TOU demand tariff can result in lost NEG even at smaller system capacities (i.e., 2.5kW$_{DC}$).

The results show that the surrendered NEG rule can limit investors' options regarding system capacity and forces additional costs that were initially overlooked. For example, even at 6.5kW$_{DC}$, the Duke customer surrenders more than 4,000 kWh and the Progress customer surrenders more than 1,300 kWh. Clearly, at higher system capacities, the amounts get more significant. For example, at 9 kW$_{DC}$, the Duke customer surrenders 24,050 kWh and the Progress customer surrenders 14,293 kWh. In the context of the reference cases, 24,050 kWh is almost two years' worth of the Duke customer's electric load, and 14,293 kWh is nearly one year's worth of the Progress customer's electric load.

Figure 27: Surrendered NEG over 25 Years



DISCUSSION

This study finds that in both the Duke and Progress customer reference cases, small PV ownership in North Carolina is currently a financially unattractive investment. The Duke customer yielded a -$8,111 NPV, and the Progress customer yielded a -$6,254 NPV. This discrepancy in NPVs between the Duke and Progress customer is mostly due to the reference cases' electric load profiles, current electric rates, and available incentives, of which the SunSense program is financially more beneficial than NC GreenPower. However, when compared to the state and federal investment tax credits, SunSense and NC GreenPower make less of an impact to the NPVs, especially at their current respective premiums and contract lengths. The state and federal ITC incrementally increase the NPVs of both reference cases by more than $5,500 and $7,000, respectively, for a combined increase of more than $13,000.

When the reference cases were compared using other regulated states' major incentives and climates, the results indicate that the reference cases measure well in terms of effective policies and incentives for small PV ownership with IOU customers. The reference cases yielded a higher NPV than all of these scenarios, with the exception of the scenario using New Mexico's major incentives coupled with the climate of Albuquerque.

The sensitivity analysis had the following findings:

- The system capacity choice can greatly affect the NPV and IRR of the reference cases. This is primarily due to the interactions with fixed costs (e.g., PPA administrative charges), eligibility for incentives (i.e., SunSense, NC GreenPower), and the limit of $10,500 for the state ITC.
- With a $0.50/$W_{DC}$ and $1.00/$W_{DC}$ CBI and 1-to-1 kWh ratio net metering, higher NPVs are yielded compared to the Duke and Progress customer reference cases, respectively.
- A utility PBI along with 1-to-1 kWh ratio net metering can be offered in various combinations of price and duration. Almost all combinations greater than or equal to $0.10/kWh for 5 years yields a higher NPV compared to the reference cases. In the most generous case, $0.20/kWh for 15 years, the Progress customer reference case yields an NPV of $48.
- Based on their respective baseline bills, 1-to-1 kWh ratio net metering yields a significantly higher NPV than under a TOU demand tariff, ignoring all REC benefits. The differences between the reference cases net metering under a 1-to-1 kWh ratio and under a TOU demand tariff are -$2,678 and -$2,968 in NPV for the Duke and Progress customers, respectively.

- Property taxes, which only are owed when the system contracts under a PPA or NC GreenPower, only minimally impact the NPV, especially due to the relatively short guaranteed term and the 80% property tax abatement.
- Although the discount rate on its own does not affect the negative-sign of the NPV of both reference cases, it is noteworthy that an increase from 5% to 10% changes the NPV much less than from 5% to 0%.
- The debt fraction has an impact of more than $1,500 (positively or negatively) for both reference cases when the debt fraction decreases and increases by 50%, respectively.
- The electricity rate and demand charge growth rate (within the range of EIA's AEO 2012 scenarios) impact the NPV of the reference cases less than initially expected. Even at the highest growth rate (1.1%/year), the NPV incrementally increases by only around $700 for both reference cases.
- The installed cost per Watt of $6.04 is one of the main factors causing the reference cases to yield negative NPVs. Holding all inputs constant, an installed cost of $3.45/$W_{DC}$ and $2.53/$W_{DC}$ for the Progress and Duke customer reference cases, respectively, would be required to set their respective NPVs to $0.
- Surrendered net excess generation is greatly impacted by the electric load profile and system generation in May. At system capacities as low as 2.5kW_{DC} and 6kW_{DC} for the Duke and Progress customer reference cases, respectively, net excess generation is surrendered to the utility at no compensation.

Based on the results of this study, it is concluded that for the average Duke and Progress residential customer in North Carolina, small PV ownership is still a financially unattractive investment on a larger scale. However, due to incentives from state policies and incentives, small PV ownership is much more financially attractive than it would be without any incentives and compares well regarding other similarly regulated states' current incentives and climate conditions. The sensitivity analysis from this report alludes to the need for a range of incentives and conditions to continue making small PV ownership more financially attractive. Drastic changes are required if only one variable is to make the NPV of the reference cases at least $0. Thus, an approach analyzing a set of incentives and conditions like the ones analyzed in this report may be more realistic and effective for decision makers.

LIMITATIONS AND FURTHER STUDY

This analysis is limited to the range of inputs and assumptions chosen by the study. One limitation of this study is the exclusion of other investing and financing options, such as solar leasing, third-party PPAs, community solar, and PACE financing. Although many of these options were reviewed in Part I of this report, this study did not incorporate them in Part II due to the study's time and resource constraints. Incorporating such options, undoubtedly, would greatly enhance the value and quality of this study. In fact, the results of Part II may allude to the need to make available innovative project finance structures as seen in states in California and Colorado. In third-party ownership structures, a financial analysis from the perspective of the third-party developer should be assessed as well. In such an analysis, additional factors may alter the findings, including business depreciation, larger tax appetites to take full advantage of tax credits, and lower installed costs.

A second limitation of this study is a deeper examination into the primary motivators for residential IOU customers in North Carolina investing in small PV systems. For example, the environmental benefits, change in property values[32], protection from price volatility, increased reliability, improved power quality, location-specific benefits (e.g., rural homes far from the grid), and social perception value, to name a few, may be of real economic value to the owner and of which are not currently included as a benefit in this study's cash flows. Due to the uncertainty and difficulty in the valuation of such factors, they were left out of Part II of this study.

A third limitation of this study is a comparison with other clean energy investments. The primary problems being addressed by this report are the need for more affordable and accessible clean energy sources for residential customers, and moreover, the need for more clean energy to replace current non-renewable sources of energy and supply future demand growth in North Carolina. Discussion over other clean energy sources should remain active during decision making, including utility-scale renewable energy projects, energy efficiency, and other forms of

[32] Although some financial estimates from different sources include increased property value in their financial analysis, this report was committed to being conservative. Thus, the change in home values, perception from potential home buyers, and home values after 25 years of PV operation were too uncertain to be included in this study.

distributed generation, such as fuel cells. After all, if other clean energy opportunities turn out to be more cost-effective and beneficial for the state and the environment than small PV, it would be inefficient to encourage small PV in lieu of those.

A final discussion point regards the recent merger of Duke and Progress. This study, as mentioned before, assumes that both utilities operate separately despite being allowed to collectively dispatch their power plants. Yet, there are a few caveats to consider. First, Duke Energy Corp (parent company) has promised to deliver $650 million in savings to customers over the next five years due to the savings from consolidating the assets of its subsidiaries (Duke and Progress)[33]. If this savings projection goes as planned, retail electricity prices may increase at a lower rate than this study's baseline assumption of 0.01%/year, or perhaps even decrease, causing the benefits (i.e., bill savings) from investing in a PV system to decrease. Second, in the event that certain utility policies and programs are altered or removed, the NPV of this study's reference cases would nonetheless change as well. For example, if Progress' SunSense program is removed, the NPV of the Progress reference case would most likely decrease, nearing the Duke reference case's NPV. On a similar note, if the utilities are permitted to consolidate their RECs and SRECs for complying with the REPS, programs such as SunSense may not make good business strategy to continue offering. These implications are all important factors to consider in the context of this study. Yet, it is to the author's belief that they have been adequately assessed via the scenario and sensitivity analyses.

[33] Duke Energy Corp. (2012 August 1). *Duke Energy Merger Benefits Begin Flowing to Carolinas Customers*. Retrieved from http://www.duke-energy.com/news/releases/2012080101.asp.

CONCLUSIONS

This report conducted a policy and financial analysis of small solar PV ($10kW_{DC}$ or less) ownership for Duke and Progress Energy customers in North Carolina. Part I reviewed the major policies and incentives that encourage such investments. Part II builds off the research conducted in Part I and analyzes the financial attractiveness of such investments in the form of two reference cases and subsequent scenario and sensitivity analyses.

In the context of the reference cases, the results indicate that small PV ownership for the average Duke and Progress customer is not currently financially attractive. However, due to declining installed costs and strong policies and incentives offered in North Carolina, small PV systems are much more financially attractive than it would be without those incentives and are competitive in relation to other similarly regulated states' major policies with consideration of their climate conditions. The findings from the scenario and sensitivity analyses quantitatively address the effectiveness of specific policies and incentives in North Carolina. This report, however, is not intended to offer specific recommendations for what the best set of policies and/or incentives is. Yet, it is aimed to provide qualitative (Part I) and quantitative (Part II) insight regarding the financial impact of major policies and incentives in North Carolina that may be of value for investors and decision makers.

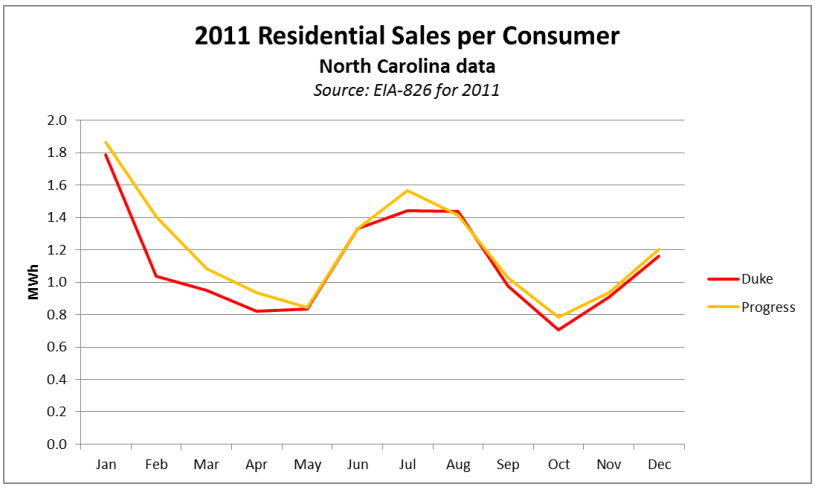
Although the results of Part II indicate that small PV ownership may still be quite a distance away from being financially attractive on a large scale for IOU residential customers in North Carolina, they do not discredit the effectiveness of some of the current policies and incentives. For example, protecting the state investment tax credit would be essential in the context of financial attractiveness of small PV ownership. At the same time, there are many opportunities to further improve the financial attractiveness of small PV investments, such as in regards to net metering policies, REPS requirements, and markets for SRECs. The findings may also support the need for effective alternative project finance structures, including third-party PPAs, solar leases, and PACE financing.

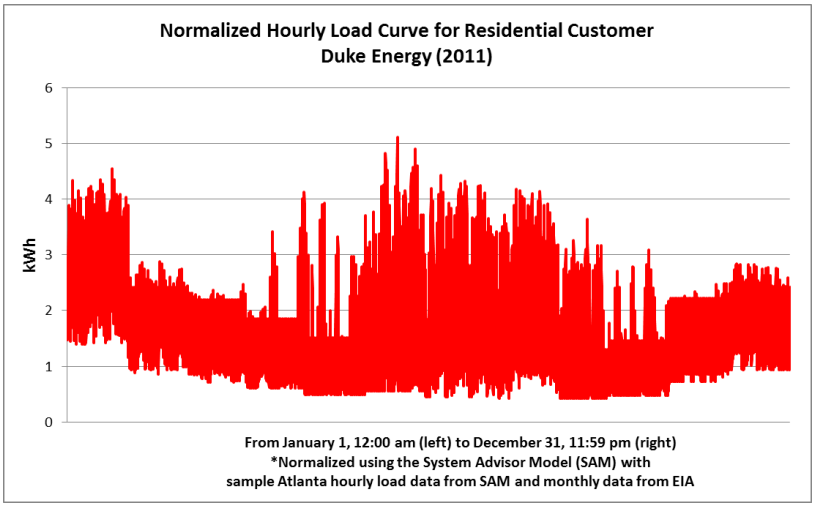
The future of small PV ownership for IOU residential customers in North Carolina is uncertain and can be impacted from many direct and indirect factors. However, with the right set of effective and efficient incentives and economic conditions, small PV ownership has the potential to become financially attractive on a large scale in North Carolina. As a source of clean energy and distributed generation, small PV for residential use would then not only benefit consumers financially, but contribute to a cleaner energy mix, strengthened economy, and cleaner environment for all citizens of North Carolina.

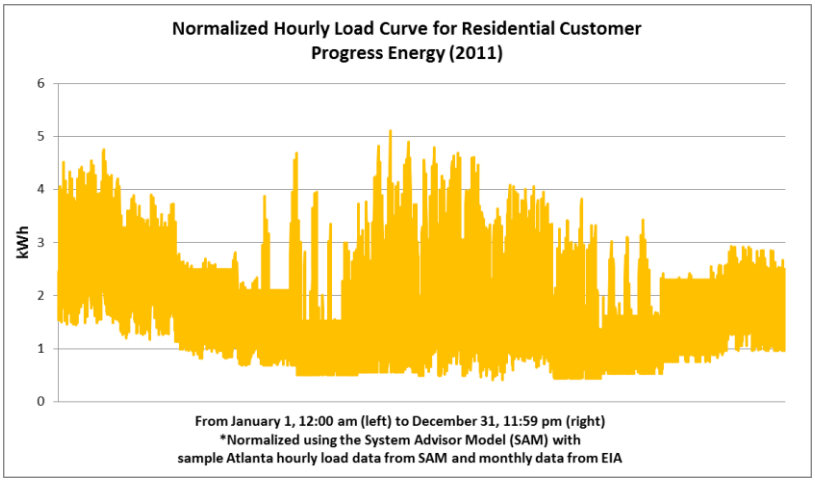
GLOSSARY

Term	Definition
1-to-1 kWh ratio	When net metering, one kWh of generation displaces one kWh of consumption regardless of when it was generated or consumed.
Discount rate	The interest rate used in discounted cash flow analysis to calculate the present value of future cash flows.
Distributed Generation (DG)	Power generation at the point of consumption.
Flat rate	Pricing structure that charges a singled fixed fee for electricity service.
Internal Rate of Return (IRR)	The discount rate that makes the net present value of a project equal to zero.
Investor-owned utility (IOU)	A utility managed as a private enterprise.
Net benefits	The difference between cash inflows and cash outflows.
Net excess generation (NEG)	Any generated kWh left over after a billing period once retail electricity consumption and on-site generation from the PV system are accounted for.
Net present value (NPV)	The difference between the present value of cash inflows and the present value of cash outflows.
Power-purchase agreement (PPA)	A contract between two parties where one party sells electricity to the other party who purchases it, often a utility.
Renewable Energy Credit (REC)	A tradable, non-tangible energy commodity representing proof that 1 MWh of electricity was generated from an eligible renewable energy resource.
Renewable portfolio standard (RPS)	A regulation requiring a specified proportion or amount of energy to be produced from renewable energy sources.
Solar Renewable Energy Credit (SREC)	A REC specifically generated by an eligible solar energy resource.
Third-party power purchase agreement (PPA)	A financial arrangement in which a third-party developer owns, operates, and maintains a PV system, and the host agrees to site the system on its property and purchase the system's electric output directly from the developer for a predetermined period.
Time-of-use (TOU) tariff	Pricing of electric services that is set differently for specific time periods; meant to encourage the shifting of consumption to a lower cost period.

APPENDIX A. ELECTRIC LOAD CALCULATION GRAPHS







APPENDIX B. ELECTRIC RATES AND CHARGES

Electric Rates and Charges (as of 8/1/12)		
Rate Type	**Flat Rate**	
Utility	Duke	Progress
Schedule	RS (NC)	RES-23
Basic Facilities Charge ($/month)	$ 9.90	$ 6.75
Energy Charges for Jul-Oct ($/kWh)	$ 0.092896	$ 0.10536
Energy Charges for Nov-Jun ($/kWh)	$ 0.092896	$ 0.09536
Rate Type	**TOU**	
Utility	Duke	Progress
Schedule	RT (NC)	R-TOUD-23
Basic Facilities Charge ($/month)	$ 14.90	$ 9.85
On-Peak Demand Charge per month for 6/1-9/30 ($/kW)	$ 7.17	$ 5.02
On-Peak Demand Charge per month for 10/1-5/31 ($/kW)	$ 3.58	$ 3.73
On-Peak Energy Charge per month ($/kWh)	$ 0.067324	$ 0.06760
Off-Peak Energy Charge per month ($/kWh)	$ 0.056309	$ 0.05386
Rate Type	**Small Power Producer**	
Utility	Duke	Progress
Schedule	PP-N (NC)	CSP-27
Duke Option A-5 Years		
Adminstrative Charge ($/month)	$ 8.17	
Facilities Charge ($/month)	$ 8.03	
Capacity Credit: On-Peak per On-peak Month ($/kWh)	$ 0.0285	
Capacity Credit: On-Peak per Off-peak Month ($/kWh)	$ 0.0056	
Energy Credit: On-Peak per month ($/kWh)	$ 0.0530	
Energy Credit: Off-Peak per month ($/kWh)	$ 0.0407	
Duke Option B-5 years		
Adminstrative Charge ($/month)	$ 8.17	
Facilities Charge ($/month)	$ 8.03	
Capacity Credit: On-Peak per Summer Month ($/kWh)	$ 0.1001	
Capacity Credit: On-Peak per Non-Summer Month ($/kWh)	$ 0.0155	
Energy Credit: On-Peak per month ($/kWh)	$ 0.0554	
Energy Credit: Off-Peak per month ($/kWh)	$ 0.0440	
Progress-5 years		
Seller Charge ($/month)		$ 4.00
Facilities Charge ($/month)		$ -
Capacity Credit: On-Peak-Summer ($/kWh)		$ 0.0343
Capacity Credit: On-Peak-Non-Summer ($/kWh)		$ 0.0283
Energy Credit: On-Peak kWh ($/kWh)		$ 0.0575
Energy Credit: Off-Peak kWh ($/kWh)		$ 0.0475

**All on-peak and off-peak definitions for each respective rate schedule were accounted for when modeling each hour, day, and month.*

APPENDIX C. PART II MODEL INTERMEDIATE STEPS

System Advisor Model

As mentioned, Part II of this study builds off the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory. SAM is a performance and financial model designed to facilitate decision making for people involved in the energy industry. Part II, however, only uses SAM as an intermediate step to this study's Excel cash flow model. These intermediate steps utilized the following from SAM:

(1) Projected PV system hourly generation (kWh) based on climate, location, and system specifications.
   - The user-decided inputs[34] for obtaining these from SAM included:
     - DC to AC Derate Factor: 0.84
     - Array Tracking Mode: Fixed
     - Tilt: 36 degrees
     - Azimuth: 180 degrees
     - System Capacity: 0.5 – 10 kW_{DC} (in increments of 0.5)
     - Climate/Location: NC/Raleigh, AZ/Phoenix, CO/Boulder, NM/Albuquerque, NV/Las Vegas
     - System Degradation: 0.5% per year
     - Availability: 100%

(2) Electric load calculation for an average[35] Duke and Progress customer in North Carolina
   - The process first used EIA-826 "Monthly Electric Utility Sales and Revenue Data" to calculate the average sales per month (MWh) in 2011 for both Duke and Progress residential data (see Appendix A). This monthly load data was coupled with SAM's simulated hourly load for Atlanta (closest SAM-provided location to North Carolina) to execute the "Normalize supplied load profile to monthly utility bill data" tool in SAM. Using this tool results in simulated hourly load profiles for both Duke and Progress residential customers. *Note: the maximum simulated demand in a single hour throughout the year was roughly 5.1kW for both the Duke and Progress residential customer case, and the annual load (unchanged by the simulation) was equal to the EIA-826 data calculated, that is, 14,398kWh and 13,408kWh for the average Progress and Duke residential customer, respectively.*

(3) The cash flow format used in this study's Excel model was similar to that used by SAM. However, this study's format is unique in a few ways. Such changes were made to better analyze the periods when entries are inputted, whether entries are benefits (cash in) or costs (cash out), and incorporate entries calculated outside of SAM.

[34] Certain inputs are the same inputs as NCSEA's *Levelized Cost of Solar Photovoltaics in North Carolina* report used, including the DC to AC derate factor, array tracking mode, tilt, and azimuth. This study agrees with those choices of inputs and thus used the same inputs.

[35] "Average", or typical, was based on averaged load data from EIA and tools from SAM. Neither Duke's or Progress' average residential hourly load data, as calculated in this report, is intended to actually represent a real household. However, they are meant to be an estimate of an average residential load profile for a Duke and Progress customer in North Carolina.

APPENDIX D. CASH FLOW FOR DUKE CUSTOMER REFERENCE CASE

	Financial Cash Flows for an average NC IOU residential customer Investing in a Solar Photovoltaic system																										
	Calendar Year	1/1/2013	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	Project Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
1	A. Cash In																										
2	Loan Proceeds	12,200.80																									
3	*Baseline Bill ($)*		*1,364.35*	*1,365.60*	*1,366.84*	*1,368.09*	*1,369.34*	*1,370.59*	*1,371.84*	*1,373.09*	*1,374.35*	*1,375.60*	*1,376.86*	*1,378.12*	*1,379.38*	*1,380.64*	*1,381.90*	*1,383.16*	*1,384.43*	*1,385.69*	*1,386.96*	*1,388.23*	*1,389.50*	*1,390.77*	*1,392.04*	*1,393.31*	*1,394.59*
4	*New Bill ($)*		*1,364.35*	*1,365.60*	*1,366.84*	*1,368.09*	*1,369.34*	*848.11*	*851.45*	*854.79*	*858.12*	*861.44*	*864.76*	*868.06*	*871.37*	*874.66*	*877.95*	*881.23*	*884.51*	*887.77*	*891.04*	*894.29*	*897.54*	*900.78*	*904.01*	*907.24*	*910.46*
5	*SunSense Bill Credit ($)*		-	-	-	-	-																				
6	Bill Saving ($)		-	-	-	-	-	522.48	520.39	518.31	516.23	514.16	512.11	510.05	508.01	505.98	503.95	501.93	499.92	497.92	495.93	493.94	491.96	489.99	488.03	486.07	484.13
7	PPA Income ($)		254.63	252.39	250.15	247.93	245.72																				
8	NEG Payment ($)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Benefits [Savings+PPA] ($)		254.63	252.39	250.15	247.93	245.72	522.48	520.39	518.31	516.23	514.16	512.11	510.05	508.01	505.98	503.95	501.93	499.92	497.92	495.93	493.94	491.96	489.99	488.03	486.07	484.13
10	State CBI	-																									
11	Utility CBI	-																									
12	Other CBI	-																									
13	Total CBI	-																									
14	Utility PBI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	NC GreenPower		459.07	456.78	454.49	452.22	449.96	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Total PBI		459.07	456.78	454.49	452.22	449.96	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Cash In	12,200.80	713.71	709.17	704.65	700.15	695.68	522.48	520.39	518.31	516.23	514.16	512.11	510.05	508.01	505.98	503.95	501.93	499.92	497.92	495.93	493.94	491.96	489.99	488.03	486.07	484.13
18	B. Cash Out																										
19	System Cost before Sales Tax	24,160.00																									
20	Sales Tax on System	241.60																									
21	System Cost After Sales Tax	24,401.60																									
22	Fixed O&M		80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00
23	*Property Assessed Value*		*4,832.00*	*4,638.72*	*4,445.44*	*4,252.16*	*4,058.88*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Property Taxes		63.39	60.86	58.32	55.78	53.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Operating Costs		143.39	140.86	138.32	135.78	133.25	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00
26	Debt Interest Payment		945.56	879.51	808.34	731.66	649.03	560.00	464.06	360.70	249.32	129.31															
27	Debt Principal Repayment		852.27	918.32	989.49	1,066.17	1,148.80	1,237.83	1,333.76	1,437.13	1,548.51	1,668.52															
28	Debt Total Payment		1,797.83	1,797.83	1,797.83	1,797.83	1,797.83	1,797.83	1,797.83	1,797.83	1,797.83	1,797.83															
29	*State Taxable Income on Equity*		*713.71*	*709.17*	*704.65*	*700.15*	*695.68*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	*Deductible Expenses*		*63.39*	*60.86*	*58.32*	*55.78*	*53.25*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	State Income Taxes (marginal effect)		50.40	50.24	50.09	49.94	49.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	State ITC		(1,708.11)	(1,708.11)	(1,708.11)	(1,708.11)	(1,708.11)																				
33	State Income Tax (Savings)		(1,657.71)	(1,657.87)	(1,658.02)	(1,658.17)	(1,658.32)																				
34	*Federal Taxable Income on Equity*		*713.71*	*709.17*	*704.65*	*700.15*	*695.68*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	*Deductible Expenses (incl. state taxes)*		*(1,594.32)*	*(1,597.01)*	*(1,599.70)*	*(1,602.39)*	*(1,605.08)*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Federal Income Taxes (marginal effect)		646.25	645.73	645.22	644.71	644.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Federal ITC		(7,320.48)																								
38	Federal Income Tax (Savings)		(6,674.23)	645.73	645.22	644.71	644.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Total Cash Out	24,401.60	(6,390.73)	926.55	923.34	920.15	916.96	1,877.83	1,877.83	1,877.83	1,877.83	1,877.83	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00
40	C. Cash Flow to NC IOU Customer	(12,200.80)	7,104.43	(217.38)	(218.70)	(220.00)	(221.29)	(1,355.34)	(1,357.44)	(1,359.52)	(1,361.60)	(1,363.66)	432.11	430.05	428.01	425.98	423.95	421.93	419.92	417.92	415.93	413.94	411.96	409.99	408.03	406.07	404.13
41	Present Value of Cash Flow	(12,200.80)	6,766.12	(197.17)	(188.92)	(180.99)	(173.38)	(1,011.38)	(964.70)	(920.18)	(877.70)	(837.17)	252.64	239.47	226.98	215.15	203.93	193.29	183.21	173.65	164.60	156.01	147.87	140.16	132.84	125.91	119.34
42	Discounted Payback	(12,200.80)	(5,434.68)	(5,631.85)	(5,820.76)	(6,001.76)	(6,175.14)	(7,186.52)	(8,151.22)	(9,071.40)	(9,949.10)	(10,786.27)	(10,533.63)	(10,294.16)	(10,067.17)	(9,852.03)	(9,648.10)	(9,454.81)	(9,271.60)	(9,097.94)	(8,933.35)	(8,777.34)	(8,629.47)	(8,489.31)	(8,356.47)	(8,230.56)	(8,111.22)
43	Net Present Value	$ (8,111.22)																									
44	Internal Rate of Return	-4.98%																									

APPENDIX E. CASH FLOW FOR PROGRESS CUSTOMER REFERENCE CASE

Financial Cash Flows for an average NC IOU residential customer Investing in a Solar Photovoltaic system

	Calendar Year	1/1/2013	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	Project Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
1	**A. Cash In**																										
2	**Loan Proceeds**	11,215.40																									
3	***Baseline Bill ($)***		*1,175.48*	*1,176.54*	*1,177.60*	*1,178.66*	*1,179.72*	*1,509.05*	*1,510.48*	*1,511.91*	*1,513.34*	*1,514.77*	*1,516.21*	*1,517.64*	*1,519.08*	*1,520.52*	*1,521.96*	*1,523.40*	*1,524.84*	*1,526.28*	*1,527.73*	*1,529.18*	*1,530.62*	*1,532.07*	*1,533.52*	*1,534.98*	*1,536.43*
4	***New Bill ($)***		*826.70*	*829.15*	*831.60*	*834.05*	*836.49*	*952.83*	*956.48*	*960.13*	*963.77*	*967.41*	*971.03*	*974.65*	*978.26*	*981.87*	*985.46*	*989.05*	*992.64*	*996.21*	*999.78*	*1,003.34*	*1,006.89*	*1,010.44*	*1,013.98*	*1,017.52*	*1,021.04*
5	***SunSense Bill Credit ($)***		*181.44*	*181.44*	*181.44*	*181.44*	*181.44*																				
6	**Bill Saving ($)**		530.23	528.83	527.44	526.05	524.67	556.22	554.00	551.78	549.57	547.37	545.17	542.99	540.82	538.65	536.49	534.34	532.20	530.07	527.95	525.84	523.73	521.63	519.54	517.46	515.39
7	**PPA Income ($)**		-	-	-	-	-																				
8	**NEG Payment ($)**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	**Benefits [Savings+PPA] ($)**		530.23	528.83	527.44	526.05	524.67	556.22	554.00	551.78	549.57	547.37	545.17	542.99	540.82	538.65	536.49	534.34	532.20	530.07	527.95	525.84	523.73	521.63	519.54	517.46	515.39
10	**State CBI**	-																									
11	**Utility CBI**	3,360.00																									
12	**Other CBI**	-																									
13	**Total CBI**	3,360.00																									
14	**Utility PBI**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	**NC GreenPower**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	**Total PBI**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total Cash In**	**14,575.40**	**530.23**	**528.83**	**527.44**	**526.05**	**524.67**	**556.22**	**554.00**	**551.78**	**549.57**	**547.37**	**545.17**	**542.99**	**540.82**	**538.65**	**536.49**	**534.34**	**532.20**	**530.07**	**527.95**	**525.84**	**523.73**	**521.63**	**519.54**	**517.46**	**515.39**
18	**B. Cash Out**																										
19	**System Cost before Sales Tax**	24,160.00																									
20	**Sales Tax on System**	1,630.80																									
21	**System Cost After Sales Tax**	25,790.80																									
22	**Fixed O&M**		80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00
23	***Property Assessed Value***		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Property Taxes**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	**Total Operating Costs**		80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00
26	**Debt Interest Payment**		869.19	808.48	743.06	672.56	596.61	514.77	426.58	331.57	229.18	118.87															
27	**Debt Principal Repayment**		783.43	844.15	909.57	980.06	1,056.02	1,137.86	1,226.04	1,321.06	1,423.44	1,533.76															
28	**Debt Total Payment**		1,652.63	1,652.63	1,652.63	1,652.63	1,652.63	1,652.63	1,652.63	1,652.63	1,652.63	1,652.63															
29	***State Taxable Income on Equity***		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	***Deductible Expenses***		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	**State Income Taxes (marginal effect)**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	**State ITC**		(1,570.16)	(1,570.16)	(1,570.16)	(1,570.16)	(1,570.16)																				
33	**State Income Tax (Savings)**		(1,570.16)	(1,570.16)	(1,570.16)	(1,570.16)	(1,570.16)																				
34	***Federal Taxable Income on Equity***		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	***Deductible Expenses (incl. state taxes)***		*(1,570.16)*	*(1,570.16)*	*(1,570.16)*	*(1,570.16)*	*(1,570.16)*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	**Federal Income Taxes (marginal effect)**		439.64	439.64	439.64	439.64	439.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	**Federal ITC**		(6,729.24)																								
38	**Federal Income Tax (Savings)**		(6,289.60)	439.64	439.64	439.64	439.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	**Total Cash Out**	**25,790.80**	**(6,127.13)**	**602.11**	**602.11**	**602.11**	**602.11**	**1,732.63**	**1,732.63**	**1,732.63**	**1,732.63**	**1,732.63**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**	**80.00**
40	**C. Cash Flow to NC IOU Customer**	**(11,215.40)**	**6,657.35**	**(73.29)**	**(74.68)**	**(76.06)**	**(77.44)**	**(1,176.40)**	**(1,178.63)**	**(1,180.85)**	**(1,183.06)**	**(1,185.26)**	**465.17**	**462.99**	**460.82**	**458.65**	**456.49**	**454.34**	**452.20**	**450.07**	**447.95**	**445.84**	**443.73**	**441.63**	**439.54**	**437.46**	**435.39**
41	Present Value of Cash Flow	(11,215.40)	6,340.33	(66.47)	(64.51)	(62.58)	(60.68)	(877.85)	(837.63)	(799.25)	(762.61)	(727.65)	271.98	257.81	244.38	231.65	219.58	208.14	197.30	187.01	177.27	168.03	159.27	150.97	143.10	135.64	128.57
42	Discounted Payback	(11,215.40)	(4,875.07)	(4,941.54)	(5,006.05)	(5,068.62)	(5,129.30)	(6,007.15)	(6,844.78)	(7,644.03)	(8,406.64)	(9,134.29)	(8,862.31)	(8,604.50)	(8,360.12)	(8,128.47)	(7,908.89)	(7,700.75)	(7,503.45)	(7,316.44)	(7,139.17)	(6,971.14)	(6,811.87)	(6,660.89)	(6,517.79)	(6,382.15)	(6,253.58)
43	**Net Present Value**	**$ (6,253.58)**																									
44	Internal Rate of Return	**-3.28%**																									

APPENDIX F. VARIABLE INPUTS FOR REFERENCE CASES AND SCENARIO ANALYSIS

Variable Inputs	Progress Reference Case	Duke Reference Case	Only state/federal ITC and net metering	Only federal ITC and net metering	No ITC. Only net metering	AZ, CO, NM, NV major policies & NC climate	AZ, CO, NM, NV major policies & AZ, CO, NM, NV climate
Climate	NC-Raleigh	NC-Raleigh	NC-Raleigh	NC-Raleigh	NC-Raleigh	NC-Raleigh	AZ-Phoenix, CO-Boulder, NM-Albuquerque, NV-Las Vegas
System Capacity (kW_{DC})	4	4	4	4	4	4	4
System Installed Cost per Capacity ($/$W_{DC}$)	6.04	6.04	6.04	6.04	6.04	6.04	6.04
Electric Load (kWh/year)	14,398	13,408	14398 and 13408	14398 and 13408	14398 and 13408	14398 and 13408	14398 and 13408
Annual Peak Load (kW)	5.105	5.109	5.105 and 5.109	5.105 and 5.109	5.105 and 5.109	5.105 and 5.109	5.105 and 5.109
Utility Provider	Progress	Duke	Progress and Duke	Progress and Duke	Progress and Duke	Progress and Duke	Progress and Duke
SunSense Program (Progress only)	Yes	No	No	No	No	No	No
Net Metering	1to1-After TOU (5yrs)	1to1-After PPA (5yrs)	1to1	1to1	1to1	1to1	1to1
Net Excess Generation	Surrendered	Surrendered	Surrendered	Surrendered	Surrendered	Rolled Over Indefinitely	Rolled Over Indefinitely
NC GreenPower	No	Yes	No	No	No	No	No
Buy-All Sell-All PPA	No	Duke Option A	No	No	No	No	No
Electricity Rate & Demand Charge Increase Factor per year (compounding)	1.001	1.001	1.001	1.001	1.001	1.001	1.001
State Investment Tax Credit (ITC)	35% (taken equally over five years)	35% (taken equally over five years)	35% (taken equally over five years)			10%(AZ), 10%(NM), 0%(CO,NV)	10%(AZ), 10%(NM), 0%(CO,NV)
Max State ITC ($)	10,500	10,500	10,500			$1000(AZ), $9000(NM)	$1000(AZ), $9000(NM)
Real Discount Rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Utility Capacity-Based Incentive ($/$W_{DC}$)	0.84 *(SunSense $1/kW_{AC}$)*					$0.10(AZ-APS), 0 (CO,NM,NV)	$0.10(AZ-APS), 0 (CO,NM,NV)
Utility Production-Based Incentive ($/kWh)						$0.15(CO-Xcel), $0.10(NM-Xcel), 0(AZ,NV)	$0.15(CO-Xcel), $0.10(NM-Xcel), 0(AZ,NV)
Utility Production-Based Incentive (years)						12(CO-Xcel), 10(NM-Xcel)	12(CO-Xcel), 10(NM-Xcel)
Federal Investment Tax Credit	30.00%	30.00%	30.00%	30.00%		30.00%	30.00%
NC GreenPower Incentive ($/kWh)		0.08					
Sales Tax	6.75%	1.00% *(privilege tax)*	6.75% (Wake County), 7.00%(Durham County)	6.75% (Wake County), 7.00%(Durham County)	6.75% (Wake County), 7.00%(Durham County)	6.75% (Wake County), 7.00%(Durham County)	6.75% (Wake County), 7.00%(Durham County)
Debt Fraction (Loan)	50%	50%	50%	50%	50%	50%	50%
Property Tax Assessed %		20% *(80% tax abatement)*					
Property Tax		1.3119%					

APPENDIX G. REFERENCE CASE AND SCENARIO ANALYSIS RESULTS

	Reference Case	Scenario		
		Only SITC, FITC, and NM	Only FITC and NM	Only NM
Duke Energy				
NPV @ 5%	$ (8,111)	$ (8,499)	$ (14,140)	$ (21,526)
IRR	-5.0%	-5.3%	-7.7%	-9.2%
Net benefits (NPV @ 0%)	$ (6,501)	$ (6,996)	$ (13,511)	$ (21,266)
Progress Energy				
NPV @ 5%	$ (6,254)	$ (7,998)	$ (13,625)	$ (20,994)
IRR	-3.3%	-4.5%	-7.1%	-8.7%
Net benefits (NPV @ 0%)	$ (4,011)	$ (6,135)	$ (12,634)	$ (20,371)

**SITC= State Investment Tax Credit; FITC= Federal Investment Tax Credit; NM=1-to-1 Net Metering*

	Scenarios with Major Policies and Incentives with Raleigh, NC Climate			
	Arizona	Colorado	New Mexico	Nevada
Duke Energy				
NPV @ 5%	$ (12,304)	$ (9,657)	$ (8,265)	$ (14,140)
IRR	-6.9%	-5.2%	-4.3%	-7.7%
Net benefits (NPV @ 0%)	$ (11,341)	$ (7,689)	$ (5,992)	$ (13,511)
Progress Energy				
NPV @ 5%	$ (11,790)	$ (9,143)	$ (7,754)	$ (13,625)
IRR	-6.3%	-4.5%	-3.6%	-7.1%
Net benefits (NPV @ 0%)	$ (10,464)	$ (6,812)	$ (5,119)	$ (12,634)

	Scenarios with Major Policies and Incentives with respective climates			
	Arizona	Colorado	New Mexico	Nevada
Duke Energy				
NPV @ 5%	$ (10,656)	$ (8,354)	$ (5,292)	$ (12,218)
IRR	-4.9%	-3.7%	-0.8%	-5.4%
Net benefits (NPV @ 0%)	$ (8,446)	$ (5,629)	$ (1,152)	$ (10,136)
Progress Energy				
NPV @ 5%	$ (10,039)	$ (7,789)	$ (4,662)	$ (11,585)
IRR	-4.2%	-3.0%	0.0%	-4.7%
Net benefits (NPV @ 0%)	$ (7,389)	$ (4,663)	$ (70)	$ (9,049)

**System Advisor Model outputs system generation based on solar PV potential of the location, or climate*
***Climates: AZ=Phoenix, CO=Boulder, NM=Albuquerque, NV=Las Vegas*

APPENDIX H. SENSITIVITY ANALYSIS RESULTS

	Sensitivity Analysis of System Capacity																			
kW_{DC}	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0
Duke Energy																				
NPV @ 5%	$ (1,503)	$ (2,447)	$ (3,391)	$ (4,335)	$ (5,279)	$ (6,223)	$ (7,167)	$ (8,111)	$ (9,055)	$ (10,109)	$ (11,718)	$ (14,664)	$(16,431)	$(18,199)	$(19,966)	$(21,734)	$(23,503)	$(25,465)	$(27,795)	$(30,332)
IRR	-6.8%	-5.9%	-5.5%	-5.3%	-5.2%	-5.1%	-5.0%	-5.0%	-4.9%	-5.0%	-5.2%	-5.9%	-6.1%	-6.2%	-6.3%	-6.4%	-6.5%	-6.6%	-6.9%	-7.3%
Net benefits (NPV @ 0%)	$ (1,378)	$ (2,110)	$ (2,842)	$ (3,573)	$ (4,305)	$ (5,037)	$ (5,769)	$ (6,501)	$ (7,233)	$ (8,092)	$ (9,592)	$ (12,706)	$(14,395)	$(16,084)	$(17,773)	$(19,462)	$(21,153)	$(23,078)	$(25,588)	$(28,584)
Progress Energy																				
NPV @ 5%	$ (995)	$ (1,991)	$ (2,986)	$ (3,981)	$ (3,908)	$ (4,690)	$ (5,472)	$ (6,254)	$ (7,035)	$ (7,818)	$ (8,785)	$ (10,189)	$(15,598)	$(17,309)	$(19,021)	$(20,732)	$(22,427)	$(24,118)	$(26,049)	$(28,364)
IRR	-4.5%	-4.5%	-4.5%	-4.5%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.4%	-3.6%	-5.4%	-5.5%	-5.7%	-5.8%	-5.9%	-5.9%	-6.0%	-6.3%
Net benefits (NPV @ 0%)	$ (761)	$ (1,523)	$ (2,284)	$ (3,046)	$ (2,507)	$ (3,009)	$ (3,510)	$ (4,011)	$ (4,513)	$ (5,015)	$ (5,731)	$ (6,951)	$(12,974)	$(14,566)	$(16,160)	$(17,754)	$(19,327)	$(20,882)	$(22,729)	$(25,201)

	Sensitivity Analysis of Utility Capacity-Based Incentives				
$/$kW_{DC}$	0.00	0.50	1.00	1.50	2.00
Duke Energy					
NPV @ 5%	$ (8,499)	$ (7,369)	$ (6,239)	$ (5,109)	$ (3,979)
IRR	-5.3%	-4.5%	-3.6%	-2.7%	-1.5%
Net benefits (NPV @ 0%)	$ (6,996)	$ (5,627)	$ (4,257)	$ (2,888)	$ (1,518)
Progress Energy					
NPV @ 5%	$ (7,998)	$ (6,868)	$ (5,738)	$ (4,608)	$ (3,478)
IRR	-4.5%	-3.8%	-2.9%	-1.8%	-0.7%
Net benefits (NPV @ 0%)	$ (6,135)	$ (4,765)	$ (3,396)	$ (2,026)	$ (656)

**All cases used net metering under a 1-to-1 kWh ratio for the full 25-year project life, and did not use any other REC incentive.*

	Sensitivity Analysis of Utility Production-Based Incentives											
$/kWh	0.05			0.10			0.15			0.20		
Contract Length (years)	5	10	15	5	10	15	5	10	15	5	10	15
Duke Energy												
NPV @ 5%	$ (7,682)	$ (7,005)	$ (6,488)	$ (6,864.50)	$ (5,510.57)	$ (4,475.98)	$ (6,047.23)	$ (4,016.33)	$ (2,464.46)	$ (5,229.96)	$ (2,522.10)	$ (452.93)
IRR	-4.8%	-4.1%	-3.3%	-4.3%	-2.8%	-1.0%	-3.7%	-1.1%	1.6%	-3.1%	0.8%	4.3%
Net benefits (NPV @ 0%)	$ (6,053.05)	$ (5,055.73)	$ (4,083.09)	$ (5,109.67)	$ (3,115.03)	$ (1,169.75)	$ (4,166.29)	$ (1,174.32)	$ 1,743.59	$ (3,222.91)	$ 766.38	$ 4,656.93
Progress Energy												
NPV @ 5%	$ (7,180.50)	$ (6,503.54)	$ (5,986.24)	$ (6,363.24)	$ (5,009.30)	$ (3,974.72)	$ (5,545.97)	$ (3,515.07)	$ (1,963.19)	$ (4,728.70)	$ (2,020.84)	$ 48.33
IRR	-4.1%	-3.4%	-2.5%	-3.5%	-2.0%	-0.3%	-2.9%	-0.3%	2.3%	-2.2%	1.7%	5.1%
Net benefits (NPV @ 0%)	$ (5,191.24)	$ (4,193.92)	$ (3,221.28)	$ (4,247.86)	$ (2,253.22)	$ (307.94)	$ (3,304.48)	$ (312.51)	$ 2,605.40	$ (2,361.10)	$ 1,628.19	$ 5,518.74

**All cases used net metering under a 1-to-1 kWh ratio for the full 25-year project life, and did not use any other REC incentive.*

APPENDIX H. SENSITIVITY ANALYSIS RESULTS *continued*

	Sensitivity Analysis of Net Metering Policies	
	Time of Use	1-to-1 (flat rate)
Duke Energy		
NPV @ 5%	$ (11,177)	$ (8,499)
IRR	-10.1%	-5.3%
Net benefits (NPV @ 0%)	$ (11,695)	$ (6,996)
Progress Energy		
NPV @ 5%	$ (10,966)	$ (7,998)
IRR	-9.7%	-4.5%
Net benefits (NPV @ 0%)	$ (11,348)	$ (6,135)

**All cases net metered for the full 25-year project life, and did not use any REC incentive.*

	Sensitivity Analysis of Debt Fraction				
	0%	25%	50%	75%	100%
Duke Energy					
NPV @ 5%	$ (6,430)	$ (7,270)	$ (8,111)	$ (8,952)	$ (9,792.77)
IRR	-0.4%	-2.5%	-5.0%	-7.4%	*
Net benefits (NPV @ 0%)	$ (724)	$ (3,613)	$ (6,501)	$ (9,390)	$ (12,278.86)
Progress Energy					
NPV @ 5%	$ (4,708)	$ (5,481)	$ (6,254)	$ (7,026)	$ (7,799)
IRR	0.8%	-1.0%	-3.3%	-5.7%	*
Net benefits (NPV @ 0%)	$ 1,299	$ (1,356)	$ (4,011)	$ (6,667)	$ (9,322)

**Since there is more than one IRR for this case (one positive, one negative), the IRR was left out.*

	Sensitivity Analysis of Property Tax (Assessed Percentage)		
	0%	20%	100%
Duke Energy			
NPV @ 5%	$ (7,943)	$ (8,111)	$ (8,785)
IRR	-4.9%	-5.0%	-5.3%
Net benefits (NPV @ 0%)	$ (6,308)	$ (6,501)	$ (7,276)

	Sensitivity Analysis of Discount Rate				
	0.0%	2.5%	5.0%	7.5%	10.0%
Duke Energy					
NPV	$ (6,501)	$ (7,605)	$ (8,111)	$ (8,304)	$ (8,337)
Progress Energy					
NPV	$ (4,011)	$ (5,482)	$ (6,254)	$ (6,644)	$ (6,828)

APPENDIX H. SENSITIVITY ANALYSIS RESULTS *continued*

	Sensitivity Analysis of Electric Rate and Demand Charge Growth Rate						
%/year	-0.2%	-0.1%	0%	0.1%	0.2%	0.9%	1.1%
Duke Energy							
NPV @ 5%	$ (8,297)	$ (8,236)	$ (8,174)	$ (8,111)	$ (8,048)	$ (7,576)	$ (7,433)
IRR	-5.5%	-5.3%	-5.1%	-5.0%	-4.8%	-3.7%	-3.4%
Net benefits (NPV @ 0%)	$ (6,925)	$ (6,786)	$ (6,645)	$ (6,501)	$ (6,356)	$ (5,270)	$ (4,938)
Progress Energy							
NPV @ 5%	$ (6,459)	$ (6,392)	$ (6,323)	$ (6,254)	$ (6,183)	$ (5,661)	$ (5,503)
IRR	-3.8%	-3.6%	-3.4%	-3.3%	-3.1%	-2.0%	-1.7%
Net benefits (NPV @ 0%)	$ (4,472)	$ (4,321)	$ (4,167)	$ (4,011)	$ (3,853)	$ (2,673)	$ (2,312)
**Growth rates are compounding year to year*							

	Sensitivity Analysis of Installed Cost per Watt									
$/$W_{DC}$	6.04	5.65	5.28	4.94	4.63	4.35	4.08	3.84	3.45	2.53
Duke Energy										
NPV @ 5%	$ (8,111)	$ (7,210)	$ (6,355)	$ (5,570)	$ (4,853)	$ (4,207)	$ (3,583)	$ (3,028)	$ (2,122)	$ 0
IRR	-5.0%	-4.4%	-3.7%	-3.0%	-2.4%	-1.7%	-1.0%	-0.4%	0.9%	5.0%
Net benefits (NPV @ 0%)	$ (6,501)	$ (5,410)	$ (4,374)	$ (3,423)	$ (2,555)	$ (1,772)	$ (1,016)	$ (345)	$ 753	$ 3,323
Progress Energy										
NPV @ 5%	$ (6,254)	$ (5,313)	$ (4,420)	$ (3,600)	$ (2,852)	$ (2,176)	$ (1,525)	$ (946)	$ 0	$ 2,216
IRR	-3.3%	-2.5%	-1.6%	-0.8%	0.1%	1.0%	2.0%	3.0%	5.0%	12.6%
Net benefits (NPV @ 0%)	$ (4,011)	$ (2,871)	$ (1,789)	$ (795)	$ 111	$ 930	$ 1,720	$ 2,421	$ 3,568	$ 6,254

	Analysis of Surrendered Net Excess Generation under a Time of Use Demand Tariff and Associated Rules																
System Capacity kW_{DC}	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0
Duke Energy																	
kWh Surrendered	0	184	647	1,110	1,573	2,036	2,499	2,962	3,425	4,080	6,392	9,997	14,065	18,884	24,050	29,215	34,381
Progress Energy																	
kWh Surrendered	0	0	0	0	0	0	0	0	202	1,365	3,536	5,897	8,257	10,914	14,293	18,265	22,598
**All cases net metered for the full 25-year project life, and the electric loads remained constant for the respective reference case.*																	
***"kWh Surrendered" is the cumulative NEG total over the 25-year project life.*																	

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