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New Hampshire Public Utilities Commission  
Comments Pursuant to Case # IR 15-296  
Submitted September 17, 2015

**Comments Regarding Electric Grid Modernization in New Hampshire**  
*The Importance of Including Analysis of Microgrids as a Key Technology for Improving  
Grid Resiliency, Reliability & Integration of Distributed Energy Resources*

Submitted By

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## General Comments

The dramatic decrease in the cost of solar photovoltaics (PV), coupled with the steady increase of retail electricity rates and price volatility of fossil fuels, has led to a surge of solar development in states like Arizona, California, Colorado, New Jersey and North Carolina. Minnesota, despite its low solar potential during the state's long winters, is pushing forward with aggressive plans to increase solar generation over the next decade (Farrell, 2014). These trends indicate that stand-alone solar PV is reaching grid parity for many residential and commercial customers across the nation (Shah, 2014). Coupling solar PV with microturbines, battery storage and advanced power electronics in a microgrid configuration can help utilities integrate intermittent renewables while offering a variety of other benefits that should be analyzed in IR 15-296.

Microgrids can produce additional benefits beyond energy and fuel cost savings that must be accounted for in regulatory proceedings and utility resource planning. If the value of increased power quality and reliability (PQ&R), reduced emissions, deferred investment in traditional generating capacity, and fuel price hedging are included in cost-effectiveness calculations, then microgrids may represent a viable alternative to traditional services offered by utility distribution companies (UDC). Microgrids may well represent a desirable pathway for utilities operating in regulated markets to incorporate disruptive technologies as a new source of revenue, rather than a threat, which industry analysts expect to induce a major restructuring of the U.S. electricity sector over the coming decades (Farrell, 2015).

Historically, many utilities have opposed the deployment of distributed energy resources (DER), efficiency programs, and demand side management (DSM), which reduce electricity consumption and sales revenue for utilities operating in most regulated markets. As solar PV, battery storage, electric vehicles and microgrids continue to gain popularity and market share, utilities must consider innovative business solutions to incorporate these disruptive technologies in ways that maximizes cost savings for ratepayers without reducing long-term profitability, or shifting costs to customers receiving basic electricity services. I have conducted extensive research in the area of microgrid cost-benefit analysis and the application of traditional regulatory cost-effectiveness tests to evaluate microgrids against traditional generation and electric grid investments. The New Hampshire PUC should consider an in-depth analysis of microgrids as part of the IR 15-296 "Grid Modernization" including the following study areas:

- **Regulation & Policy**
- **Interconnection Standards**
- **Contracting Risk**
- **Prospective Microgrid Capacity**
- **Renewable Microgrid Prospects**
- **Development of a Microgrid Policy Roadmap**

These study areas are discussed in greater detail on the following page, and a summary of my own microgrid study results are included as an addendum.

## **New Hampshire Microgrid Feasibility Study Framework**

The New Hampshire PUC should commission a study as part of the IR 15-296 “Grid Modernization” proceedings to identify regulatory barriers to and opportunities for microgrid development that can provide improved power quality and reliability, reduced emissions, integration of renewables, and increased customer control over energy consumption. The study should also provide recommendations to address barriers and identify pathways to facilitate microgrid development.

**Regulation & Policy:** Review applicable State, Federal, and regional laws, regulations, rules, incentives, siting and permitting requirements, and practices affecting microgrid development, ownership, and operation. Analyze policies and policy gaps, and discuss how they prohibit or discourage microgrids, or, conversely, how they support microgrids.

**Interconnection Standards & Practices:** Identify New Hampshire standards and practices involving interconnection, interoperability, and control of distributed energy resources. Compare and contrast these policies with the most current federal and industry standards. Identify differences affecting microgrid development and optimization in utility systems.

**Contracting, Risk Assessment, and Financing:** Discuss how traditional contracting, risk assessment, and financing practices apply to microgrids. Analyze New Hampshire policies that affect microgrid development, valuation, and access to third-party capital.

**Prospective Microgrid Capacity:** Research and model potential electric load available to microgrids within the state of New Hampshire. Segment potential load by user groups. Discuss assumptions and limiting factors affecting derived potential capacity, as well as such factors as fuel supply and access to infrastructure.

**Renewable Microgrid Prospects:** Identify renewable resources in Minnesota potentially available for use in microgrid applications. Discuss relevant trends in technologies and resource options, and examine economic and operational factors influencing prospects for renewable microgrids in New Hampshire.

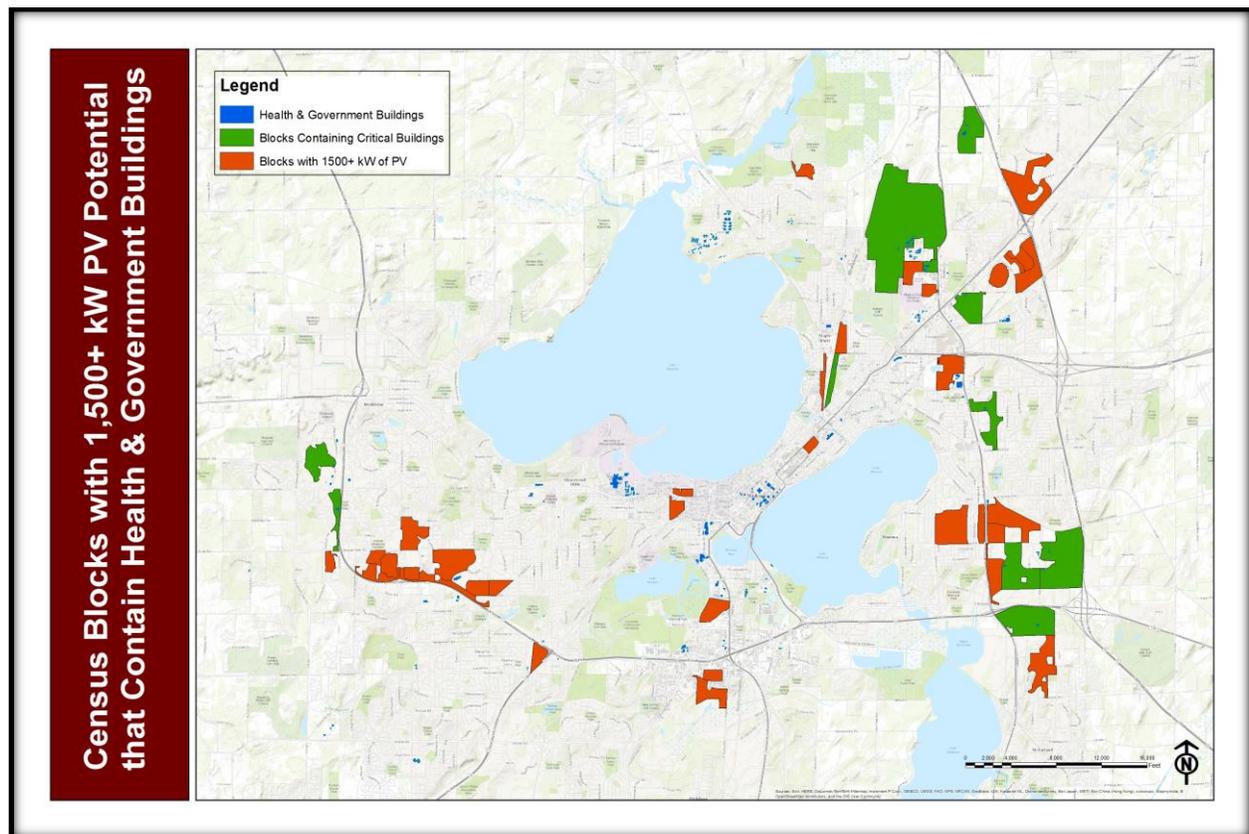
**Microgrid Policy Roadmap:** Recommend and explain policy steps that would help capture the benefits of microgrid development for Minnesota residents, and assist in their safe, cost-effective implementation and integration into the utility system.

This suggested framework is based on a study commissioned by the Minnesota Department of Commerce in 2013 ([link](#)). Completing a comprehensive study of microgrid opportunities, barriers, and economic conditions in New Hampshire will help the state keep pace with regional neighbors like Connecticut and New York who have already implemented microgrid development programs. The New Hampshire PUC can facilitate the microgrid study process by promoting collaboration between regulated utilities, ratepayer advocacy groups, and consulting firms selected through a competitive bidding process.

## Summary of Wisconsin Microgrid Research

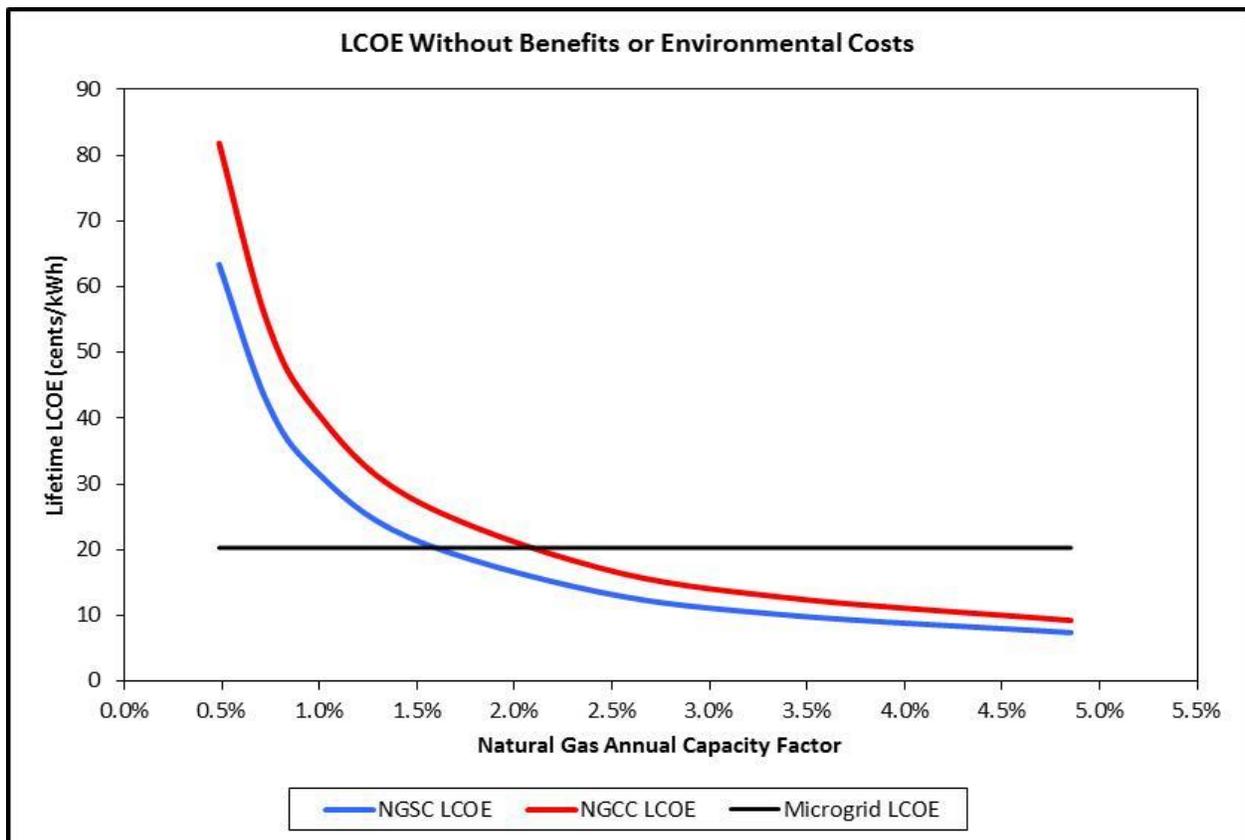
Research completed at UW-Madison with support from the Wisconsin Distributed Resources Collaborative (WIDRC), and the Wisconsin Energy Institute (WEI) shows that microgrids can deliver positive net benefits to electricity customers, the host electric utility, and society at large, under certain scenarios.

The study quantifies the costs and benefits associated with using microgrids as the main technology to promote distributed renewable electricity generation in Madison. A multi-stakeholder analytical process was employed to evaluate cost-effectiveness from the perspective of electric ratepayers served by microgrids, the local electric utility, ratepayers not served by microgrids, and electric utility regulators. The cost-effectiveness methodology combines the use of existing geographic information systems (GIS) software, and the Model for Distributed Energy Resource Networks (MoDERN), which was developed specifically for analyzing utility distribution microgrids. GIS analysis determined that there were 45 locations in Madison capable of supporting at least 1,500kW of rooftop solar PV capacity, while 11 of those locations also contain critical facilities (health and government buildings) that would benefit from improved power quality and reliability offered by microgrids. The map below shows the location of these potential microgrid development sites (green areas are sites that contain health and government buildings).

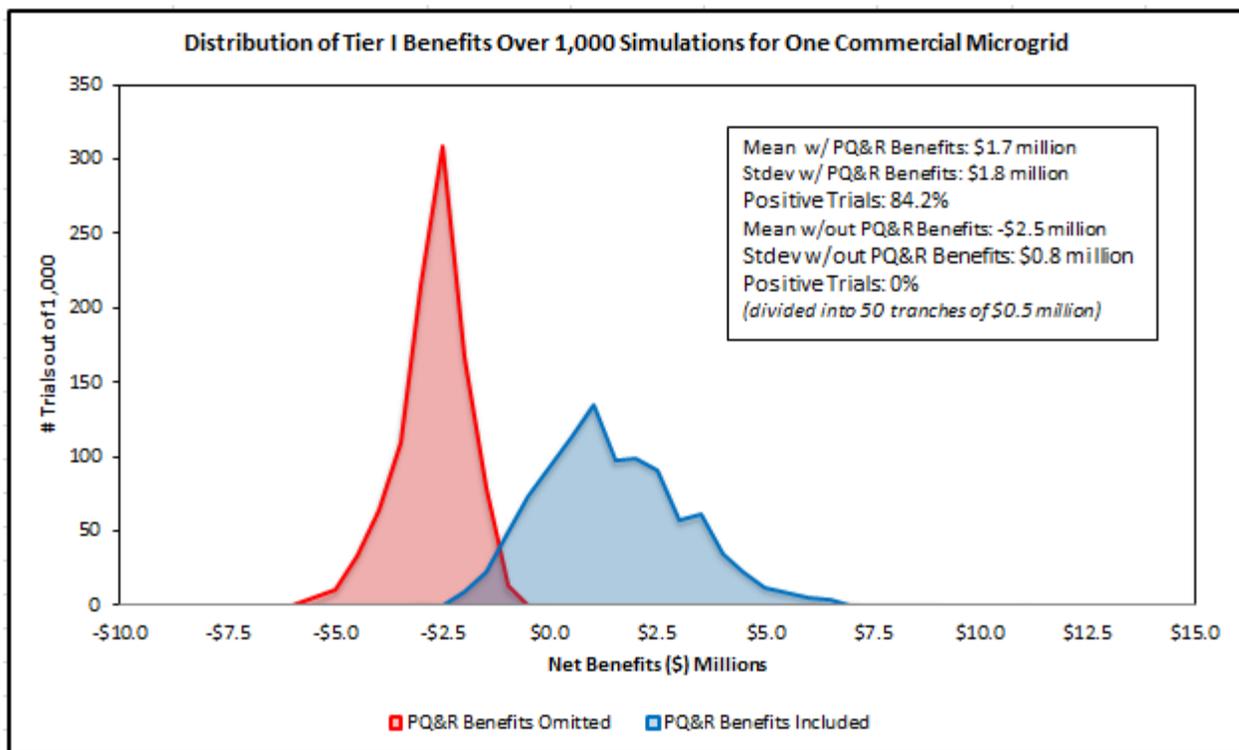


The study evaluated six microgrid deployment scenarios using widely accepted cost-effectiveness metrics developed by the California Public Utilities Commission (CPUC). The six deployment scenarios are; 1.5% and 3% of annual electricity demand in the residential, commercial and industrial sectors based on 2012 data obtained from the U.S. Energy Information Administration (EIA). Using a standard microgrid configuration consisting of 750kW of rooftop solar PV and one 1,000kW natural gas microturbine, it was determined that the 45 potential microgrid sites with at least 1,500kW of solar PV potential could support each of the microgrid deployment scenarios. Each microgrid system was estimated to cost \$8.5 million with annual operations and maintenance costs of \$250,000-\$350,000.

Over a 25-year analysis period, the levelized cost of electricity (LCOE) for one hypothetical microgrid system was found to be 17-19 cents/kWh, compared to 30-40 cents/kWh for a natural gas-fired peaking unit operating at an annual average capacity factor of 1% (based on a comparison with a 25MW unit that operates roughly 50 hours each year to meet extreme peak demand). This comparison does not account for the added benefit of increased power quality and reliability delivered to microgrid customers, which would decrease the microgrid's lifetime LCOE. This analysis shows that microgrids represent a lower cost, and less emissions intensive, alternative to building traditional power plants. However, baseload power plants that operate at much higher capacity factors are still cheaper than microgrid systems, with LCOE's ranging from 4-8 cents/kWh (Utah University, [link](#)).

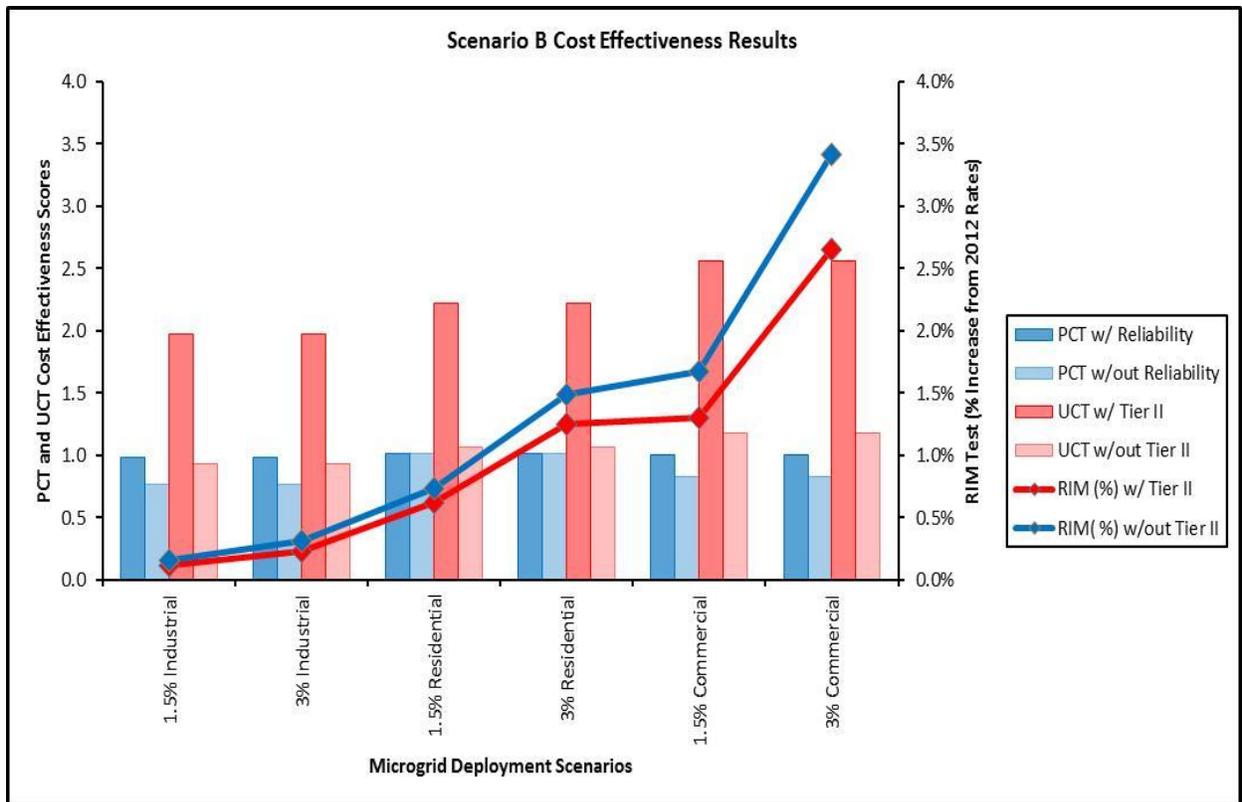
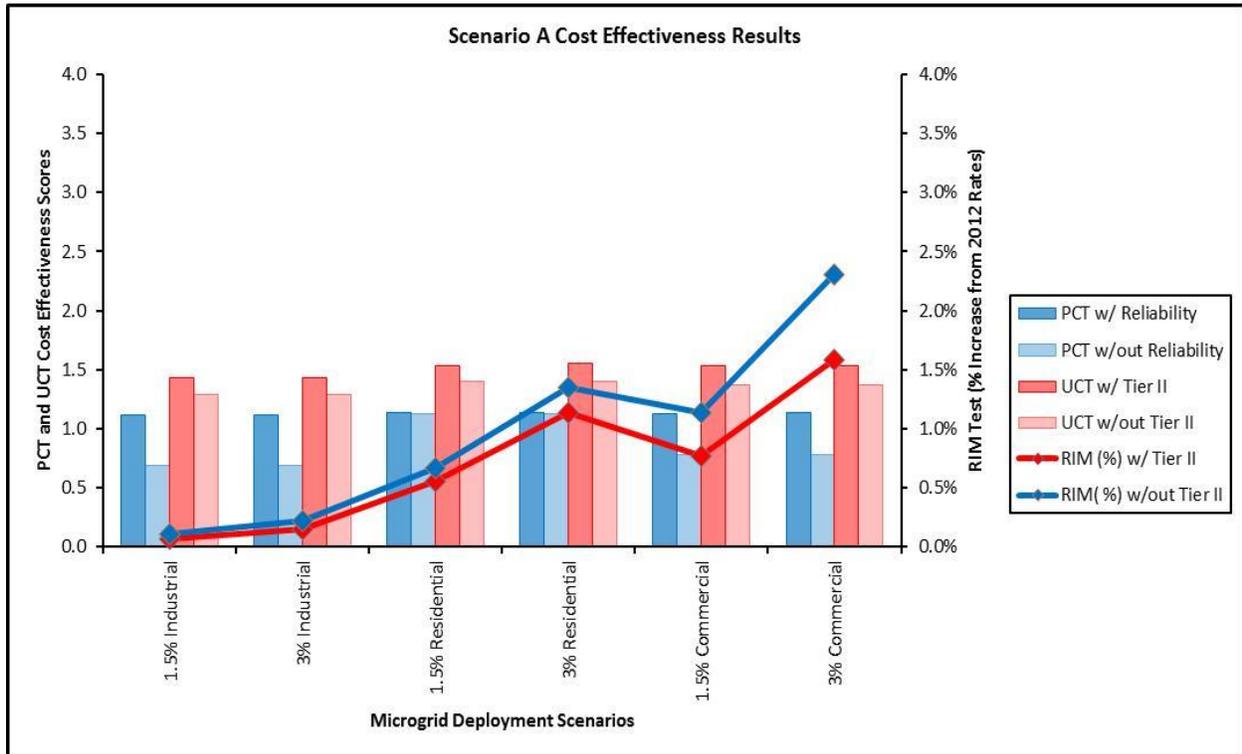


The results of the cost-effectiveness analysis found that solar PV-based microgrids capable of meeting 1.5% of annual electricity demand in each customer segment pass all three cost-effectiveness tests when built, owned and financed by the local electric utility (termed Scenario A in the study). Microgrids built and operated by a third party developer (termed Scenario B in the study) were not cost-effective under test case assumptions, but may provide positive benefits to customers who place a high value on power quality and reliability. The graph below shows the distribution of 1,000 Monte Carlo simulations that compares the lifetime net benefits received by commercial microgrid customers when the value of power quality and reliability is included, or excluded, in their lifetime net benefit calculations. Clearly, a customer who does not place a high value on power quality and reliability would not be interested in paying higher electricity rates for microgrid services, but the value of increased reliability can be significant and should not be ignored by the utility or industry regulators.



Analysis of microgrid deployment at the city-level found that 12 of the 24 scenarios tested under Scenario A passed all three cost-effectiveness tests, while none of the 24 scenarios tested under Scenario B passed all three tests (Scenarios must have a PCT and UCT (participant and utility cost test) score of at least 1.1 and a RIM (ratepayer impact measure) score lower than 1.5% to be considered cost-effective). These results show that microgrid deployment in Madison can be cost-effective for all major stakeholders at low penetration levels. Third party microgrids are only cost-effective in niche markets serving customers who place high values on power quality and reliability. However, as the cost of solar PV and microgrid power electronics continues to decline, third party microgrids may be able to offer services that are cost competitive with traditional grid services.

## Cost Effectiveness Test Results under Scenario A & B



In the figures on the previous page, the blue and red bars display the PCT and UCT scores for each microgrid deployment scenario using the numerical scale on the left vertical axis. The red and blue line graphs display the RIM test results for each microgrid deployment scenario using the percentage scale on the right vertical axis. The results clearly show that microgrid deployment under Scenario A produces higher lifetime net benefits for microgrid customers with lower rate increases on non-microgrid customers. The following tables provide a complete summary of the cost-effectiveness results under Scenario A and Scenario B. Green cells show the microgrid deployment scenarios that passed all three cost-effectiveness tests, while red cells highlight the failed cost-effectiveness tests for each microgrid deployment scenario.

### Cost Effectiveness Results under Scenario A

Tier II & Reliability	PCT	UCT	RIM (%)
1.5% Residential	1.135	1.531	0.56%
3% Residential	1.135	1.558	1.13%
1.5% Commercial	1.122	1.531	0.78%
3% Commercial	1.133	1.531	1.58%
1.5% Industrial	1.12	1.436	0.07%
3% Industrial	1.12	1.436	0.15%
<b>Tier II, No Reliability</b>			
1.5% Residential	1.124	1.531	0.56%
3% Residential	1.124	1.558	1.13%
1.5% Commercial	0.776	1.531	0.78%
3% Commercial	0.776	1.531	1.58%
1.5% Industrial	0.688	1.436	0.07%
3% Industrial	0.688	1.436	0.15%
<b>No Tier II &amp; Reliability</b>			
1.5% Residential	1.135	1.401	0.67%
3% Residential	1.135	1.401	1.36%
1.5% Commercial	1.122	1.366	1.13%
3% Commercial	1.122	1.366	2.31%
1.5% Industrial	1.12	1.289	0.11%
3% Industrial	1.12	1.289	0.23%
<b>No Tier II, No Reliability</b>			
1.5% Residential	1.124	1.401	0.67%
3% Residential	1.124	1.401	1.36%
1.5% Commercial	0.776	1.366	1.13%
3% Commercial	0.776	1.366	2.31%
1.5% Industrial	0.688	1.289	0.11%
3% Industrial	0.688	1.289	0.23%

## Cost Effectiveness Results under Scenario B

Tier II & Reliability	PCT	UCT	RIM (%)
1.5% Residential	1.017	2.221	0.62%
3% Residential	1.017	2.221	1.25%
1.5% Commercial	1.005	2.557	1.30%
3% Commercial	1.005	2.557	2.65%
1.5% Industrial	0.988	1.977	0.11%
3% Industrial	0.988	1.977	0.23%
<b>Tier II, No Reliability</b>			
1.5% Residential	1.011	2.221	0.62%
3% Residential	1.011	2.221	1.25%
1.5% Commercial	0.833	2.557	1.30%
3% Commercial	0.833	2.557	2.65%
1.5% Industrial	0.769	1.977	0.11%
3% Industrial	0.769	1.977	0.23%
<b>No Tier II &amp; Reliability</b>			
1.5% Residential	1.017	1.064	0.74%
3% Residential	1.017	1.064	1.49%
1.5% Commercial	1.005	1.185	1.68%
3% Commercial	1.005	1.185	3.42%
1.5% Industrial	0.988	0.929	0.16%
3% Industrial	0.988	0.929	0.31%
<b>No Tier II, No Reliability</b>			
1.5% Residential	1.011	1.064	0.74%
3% Residential	1.011	1.064	1.49%
1.5% Commercial	0.833	1.185	1.68%
3% Commercial	0.833	1.185	3.42%
1.5% Industrial	0.769	0.929	0.16%
3% Industrial	0.769	0.929	0.31%

The study results show that the local UDC can develop microgrids more cost-effectively for microgrid customers than a third party developer. However, if the utility is unwilling to pursue microgrid development, there are a few scenarios where microgrids could be cost-effective for all stakeholders when built and operated by a third party developer. Third party microgrids would have to serve commercial or industrial customers who place a high value on increased power quality and reliability in order to pass the 1.1 PCT cost-effectiveness threshold. Third party microgrid deployment in the industrial sector could pass all three cost-effectiveness tests if the industrial customers served by the microgrid place a high value on power quality and reliability. The 1.5% commercial/industrial and 3% industrial deployment scenarios passed the UCT and RIM tests, while a higher value for power quality and reliability benefits would result in a PCT score of 1.1 or higher. Table 28 on the following page illustrates the values for increased power quality and reliability that would be necessary for commercial and industrial customers to see lifetime net benefits and a 25-year ROI greater than 10% (reflecting a PCT score of 1.1 or higher) under Scenario B.

**An overview of the MoDERN Tool is included in the following section**

# MoDERN Toolkit Functionality and Summary of Features

**Hourly Energy & Cost Simulations**

**Annual Energy & Cost Simulations**

**Lifetime Net Benefits from Four Perspectives**

- Microgrid Project Developer
- Electric Ratepayers Served by the Microgrid
- Host Electric Utility
- Environment & Societal Benefits

**Risk Analysis Based on 1,000 Simulations**

**Cash Flow Analysis**

**Project Payback Period**

**Internal Rate of Return (IRR)**

Technology Types	Included in MoDERN
Solar PV	✓
Wind Turbines	✓
Biogas Digesters	✓
NG Microturbines w/ CHP	✓
Diesel Gensets	✓
Battery Storage	✓
Demand Response	✓
Analytical Features	
Hourly Energy Demand & Costs	✓
Lifetime Net Benefits	✓
Cash Flow/Payback Period/ROI/IRR	✓
Regulatory Cost Effectiveness Tests	✓
Risk Analysis Using 1,000 Simulations	✓
Host Utility Financial Analysis	✓

# MoDERN Input Screens

## Easy-to-Use User Interface

### Financial Inputs

New Microgrid or Existing Customer?	<b>New Microgrid</b>
Is the project financed with a loan?	Yes
Loan Downpayment (% of total costs)	20%
Amount Financed	\$215,266,000
Loan Term (years)	20
<b>Loan Interest Rate Variable</b>	5.00%
Price of BECs (\$/MWh)	\$18.00
Inflation Adjusted Rate (%)	2.54%
Annual Loan Payment	\$14,658,082
Include Deferred Tax 2 Benefits?	No
External Funding (\$)	\$0.00
Social Cost of Carbon (\$/ton)	\$15.00
Carbon Price Growth Rate (%/year)	2.10%
Hold CO2 Price Constant?	Yes
PV Installed Cost (\$/kW)	\$2,000
Momentary Power Outage Cost (\$/year)	\$5,000
Extended Power Outage Cost (\$/year)	\$50,000
Utility Incur CO2 Cost?	Yes
Demand Charge Applied During Peak Hours	Yes
Are Microgrid Self-Back Rate (\$/MWh)	\$0.0500
<b>Use Original Rates</b>	\$0.0850
On-Peak Rate for Non-MG Power	\$0.0500
On-Peak Rate for Non-MG Power	\$0.0650
Utility Rate Escalator	2.00%
Utility SOG for MG Only	61.21%
Utility SOG w/ Microgrids	19.16%
Utility SOG w/ Non-MG Rate Increases	16.20%
25-Year Ratepayer Benefit After Rate Increase	\$18,143,452
MG Utility Benefits After Rate Increase	\$227,312,012
Customer NPV of SOG 1 & SOG 2 Benefits	\$365,455,424
Additional Costs for Non-MG Customers	\$122,251,592
Total Net Benefits Across All Stakeholders	\$687,709,382
25-Year Benefits of Reduced Emissions	\$23,615,244

### Financial Structure for Costs & Benefits

MG Generation Revenue To	2nd Party Developer
MG Sales Revenue To	2nd Party Developer
MG Sales Revenue To	2nd Party Developer
Tax Credits Access To	2nd Party Developer
Loan Payments By	2nd Party Developer
Downpayments Paid By	MG Customer
Annual O&M Costs Paid By	2nd Party Developer
Annual Fuel Costs	Utility
Substation Upgrades	Utility
Transmission Lines	Utility
Distribution Lines	Utility
Salvage Value	Utility
# of MG Events per Year	0
# of Outages per Year	1

### Environmental Benefit Values

Grid CO2 (\$/MWh)	856
Grid SO2 (\$/MWh)	1.50
Grid NOx (\$/MWh)	2.50
SO2 Allowances (\$/ton)	\$0
SO2 Health Benefits (\$/ton)	\$2,754
NOx Allowances (\$/ton)	\$0
NOx Health Benefits (\$/ton)	\$1,422
Uncertain Tax 2 Benefit Values (\$/MWh)	
Auxiliary Services	\$0.0050
T&D Deferrals	\$0.0100
Capacity Deferrals	\$0.0550
Fuel Price Hedging	\$0.0055

### Microgrid Variable Inputs

	1	Commercial
Number of MGs Built / Customer Group	1	Commercial
Electric Utility / Customers Served by Each MG	Microgrid Electric	10
Actual Utility Demand Met by MG Generation		100.00%
<b>Users Defined Hourly Load</b>		
Discount Rate	5.00%	Constant
Electricity Rate Increases (%/yr)	2.00%	4.00%
Inflation Rate (%/yr)	2.00%	4.00%
Peak Hourly Load (MW) & Reliability Margin	82.4	11.91%
Average Hourly Load (MW) & Reliability Margin	42.8	10.04%
Annual Demand (MWh & demand)	376,000	23,680
Demand Response Price % Load Reduction	\$100.00	0%
Electric Consumption Variance (% of basecapacity)	80%	100%
Hold Capital Costs Constant in Sensitivity Analysis?	No	10%
Surge Price Increase (% of current price)	20%	200%
Daily Electric Service Charge (Original/MG)	\$0.0000	\$0.0000

### Microgrid Components

	Unit Size	Number
Solar PV (MW)	50,000	1
Small Wind (kW)	500	1
Storage (MWh)	5	1
Fuel Cell		
Lead Acid Battery	50	1
Capacity 2 (MW/2Hr)	7500	1
Smart Inverter	1	1
Other Microgrid Power Electronics		
Microgrid Construction & Engineering Costs (\$/kW)	\$12.00	1,200,000
Microgrid Repairs & Strategy	All Hours Load Following	Minimum 0%
Maximum Microgrid CF (%)	50%	50%
<b>Assumed Electricity Purchases</b>		
On-Peak (Microgrid Capacity and 5MW)	133,212,266	8
Off-Peak (Microgrid Capacity and 5MW)	118,814,120	8
Total	303,089,110	8
Not Retrieved Units	11,343,000	8
Grid Purchases (\$)	12,015,744	8

### Transmission & Distribution (T&D) Variables

Transmission MGs Line	20.0
Transmission MGs Line	20.0
Feeder Miles Low	8.20
Feeder Miles Low	1.00
Peak 110/125 Substation Ratio	1.00
12kV Feeder Lines (MW/Mile)	1.00
New 330/120V Substation Cost	\$11,000,000
New 115/120V Substation Cost	\$11,000,000
New 69/120V Substation Cost	\$11,000,000
130/120V Substation Upgrade	\$11,000,000
115/120V Substation Upgrade	\$5,000,000
69/120V Substation Upgrade	\$1,000,000
Substation Cost High	100%
Substation Cost Low	80%
230kV Line Cost/Mile	\$1,000,000
138kV Line Cost/Mile	\$1,200,000
69kV Line Cost/Mile	\$1,200,000
Line Cost High	100%
Line Cost Low	80%
120V Line Cost	\$400,000
120V Line Cost	\$200,000
Requires New Transmission Asset?	No
Requires new distribution lines?	No
Requires new substation?	No

Model Author: Ben Kalidounis

Version: 2.0  
Version Date: 6/15/2015  
Version Notes:

**MoDERN**

# MoDERN Input Screens

## Rate Structures & Load Curves

### Hourly Electricity & Heating Load Profiles

Hourly Defined Hourly Load (Paste Hourly Data in Y111-19W Columns)

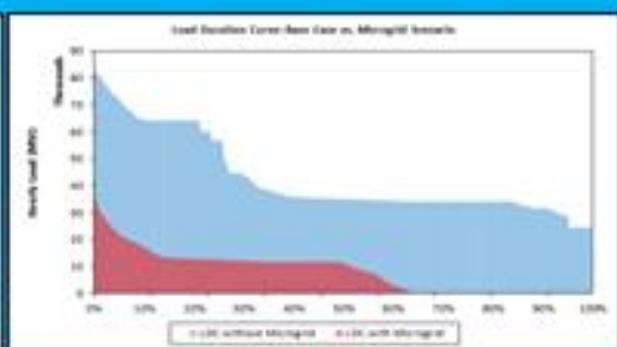
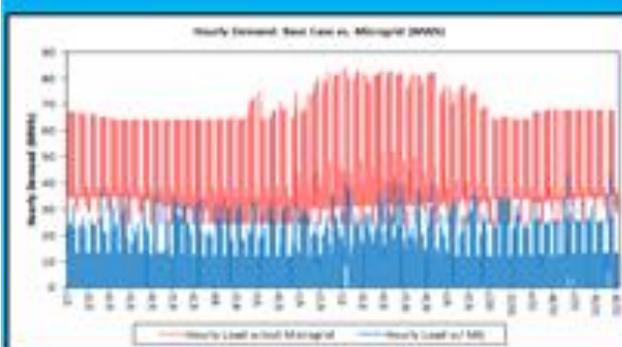
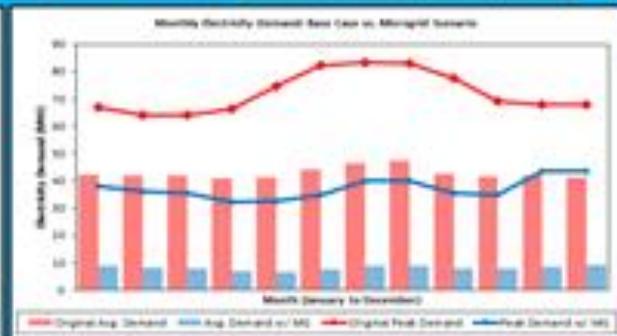
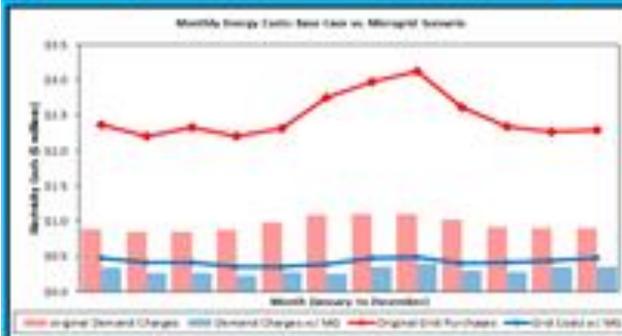
Date	Hour	2002/2003y Load	2002/2003y Load Factor	Residential Electricity Load	Residential Electricity Load Factor	Commercial Electricity Load	Commercial Electricity Load Factor	Industrial Electricity Load	Industrial Electricity Load Factor	Residential Heating Load	Residential Electricity Load Factor
1/1/2012	1	363.3	41.2%	363.3	35.4%	28.8	42.4%	26.2	76.2%	1.762	44.8%
1/1/2012	2	285.9	36.2%	431.2	36.4%	28.7	42.2%	25.8	69.1%	1.890	46.2%
1/1/2012	3	276.5	34.4%	404.1	34.4%	29.0	42.4%	25.4	68.4%	1.952	46.2%
1/1/2012	4	267.1	34.4%	367.7	28.4%	28.7	42.2%	25.1	68.2%	1.218	76.1%
1/1/2012	5	267.1	34.4%	367.7	28.2%	28.0	42.2%	25.3	68.2%	1.285	72.2%
1/1/2012	6	286.9	36.2%	427.3	36.2%	28.7	42.2%	25.4	68.1%	1.665	71.8%
1/1/2012	7	327.4	44.6%	349.8	29.2%	28.3	42.4%	26.8	72.2%	1.037	61.6%
1/1/2012	8	376.1	51.2%	734.1	52.4%	24.2	36.4%	28.1	75.4%	1.076	62.0%
1/1/2012	9	367.7	52.4%	768.8	60.4%	24.2	36.4%	28.1	76.4%	1.174	73.4%
1/1/2012	10	367.7	52.4%	638.2	43.4%	23.9	36.2%	28.1	76.4%	1.640	68.8%
1/1/2012	11	360.9	52.2%	638.2	45.4%	23.8	36.2%	28.4	76.8%	1.117	68.2%
1/1/2012	12	360.9	52.2%	631.1	44.6%	23.1	34.4%	28.4	76.8%	1.266	57.7%
1/1/2012	13	384.2	52.2%	607.8	42.4%	23.4	34.4%	28.2	76.2%	1.060	52.8%
1/1/2012	14	367.7	52.4%	585.8	42.1%	23.1	34.2%	28.1	76.4%	1.762	68.8%
1/1/2012	15	367.7	52.4%	588.4	42.4%	22.8	34.2%	28.1	76.4%	1.046	44.2%
1/1/2012	16	360.9	52.2%	626.7	44.7%	22.8	34.4%	28.4	76.8%	1.842	51.4%
1/1/2012	17	360.9	52.2%	776.1	54.8%	25.8	37.4%	28.4	76.8%	1.249	57.4%
1/1/2012	18	417.6	56.4%	1050.1	75.2%	28.2	42.2%	28.8	78.4%	1.820	62.2%
1/1/2012	19	430.4	58.2%	1232.6	87.2%	28.1	41.8%	28.4	78.2%	1.360	59.4%
1/1/2012	20	426.4	57.2%	1199.4	85.4%	28.5	42.2%	29.1	78.6%	1.282	57.4%
1/1/2012	21	408.4	57.2%	1158.1	78.2%	28.5	41.8%	29.1	78.6%	1.438	59.4%
1/1/2012	22	402.2	54.8%	1025.1	75.1%	28.8	42.2%	28.7	77.2%	1.438	60.2%
1/1/2012	23	360.9	52.2%	849.1	60.4%	28.4	41.8%	28.4	76.8%	1.014	61.2%
1/1/2012	24	346.8	47.2%	675.8	48.2%	28.8	42.2%	27.4	73.8%	1.077	61.8%

### Electricity Rates, Natural Gas Prices & Load Profiles (enter rates here to be used in the Hourly Simulator)

Month	1	2	3	4	5	6	7	8	9	10	11	12
1	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
2	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
3	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
4	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
5	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
6	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
7	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
8	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
9	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
10	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2679	\$0.2679	\$0.2679	\$0.2679	\$0.2394	\$0.2394	\$0.2394
11	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2679	\$0.2679	\$0.2679	\$0.2679	\$0.2394	\$0.2394	\$0.2394
12	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2679	\$0.2679	\$0.2679	\$0.2679	\$0.2394	\$0.2394	\$0.2394
13	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2911	\$0.2911	\$0.2911	\$0.2911	\$0.2394	\$0.2394	\$0.2394
14	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2911	\$0.2911	\$0.2911	\$0.2911	\$0.2394	\$0.2394	\$0.2394
15	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2911	\$0.2911	\$0.2911	\$0.2911	\$0.2394	\$0.2394	\$0.2394
16	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2911	\$0.2911	\$0.2911	\$0.2911	\$0.2394	\$0.2394	\$0.2394
17	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2911	\$0.2911	\$0.2911	\$0.2911	\$0.2394	\$0.2394	\$0.2394
18	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2679	\$0.2679	\$0.2679	\$0.2679	\$0.2394	\$0.2394	\$0.2394
19	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2679	\$0.2679	\$0.2679	\$0.2679	\$0.2394	\$0.2394	\$0.2394
20	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2394	\$0.2679	\$0.2679	\$0.2679	\$0.2679	\$0.2394	\$0.2394	\$0.2394
21	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
22	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729
23	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729	\$0.0729

# Hourly, Monthly, Annual Energy Consumption & Cost Analysis

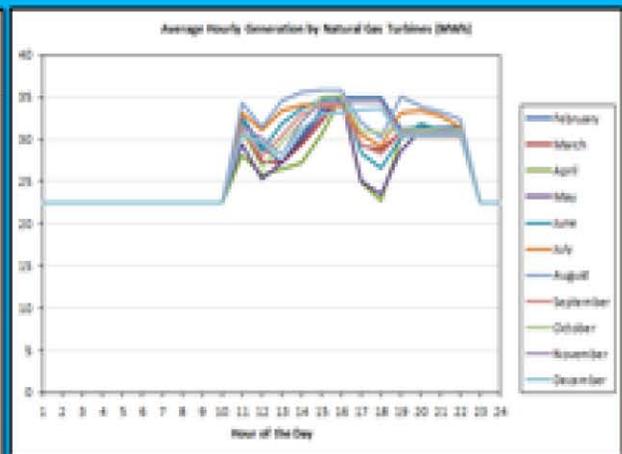
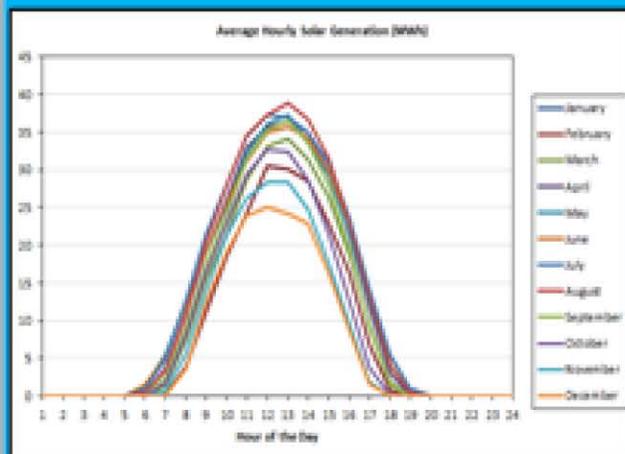
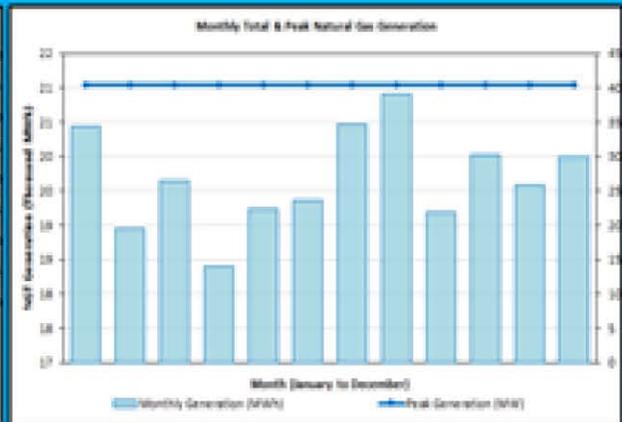
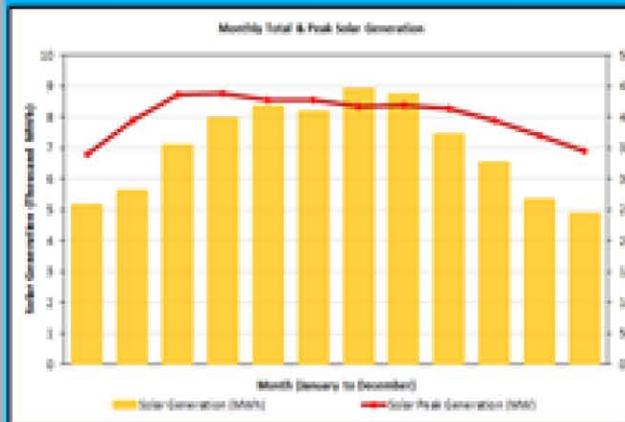
Comparison of Monthly Energy & Demand Costs			Monthly Peak Demand (MW)		
Month	Base Case Demand \$	Microgrid Demand \$	Month	Base Case Demand	Microgrid Demand
January	\$884,240	\$713,242	January	67.8	38.0
February	\$897,238	\$776,138	February	65.2	36.1
March	\$917,239	\$799,547	March	66.0	36.7
April	\$925,777	\$729,993	April	66.3	37.4
May	\$984,272	\$782,200	May	76.7	37.7
June	\$1,084,099	\$717,633	June	82.3	34.9
July	\$1,371,099	\$717,582	July	82.4	40.1
August	\$1,384,667	\$697,639	August	82.2	39.9
September	\$1,322,119	\$704,247	September	77.4	35.3
October	\$953,624	\$676,367	October	66.1	35.0
November	\$896,307	\$714,417	November	67.9	41.3
December	\$896,307	\$717,633	December	67.8	41.9
<b>Total</b>	<b>\$11,849,698</b>	<b>\$8,798,577</b>	<b>Average Peak Demand</b>	<b>73.3</b>	<b>37.3</b>
Energy Consumption Costs			Monthly Energy Consumption (MWh)		
Month	Base Case Demand \$	Microgrid Demand \$	Month	Base Case Demand	Microgrid Demand
January	\$1,300,412	\$473,495	January	21,438	6,020
February	\$1,261,448	\$411,688	February	19,247	5,819
March	\$1,310,192	\$456,411	March	21,071	5,816
April	\$1,293,618	\$348,339	April	19,389	5,110
May	\$1,318,899	\$372,487	May	20,714	5,212
June	\$1,749,742	\$389,215	June	23,818	5,765
July	\$1,675,626	\$476,789	July	24,119	6,762
August	\$1,319,989	\$484,376	August	24,296	6,389
September	\$1,315,399	\$494,409	September	27,544	5,816
October	\$1,373,849	\$476,347	October	26,999	5,791
November	\$1,216,469	\$442,388	November	26,111	6,218
December	\$1,261,699	\$474,678	December	26,741	6,748
<b>Total</b>	<b>\$17,388,639</b>	<b>\$4,616,513</b>	<b>Monthly Average</b>	<b>21,628.3</b>	<b>5,950.8</b>
<b>Energy &amp; Demand</b>	<b>\$30,638,339</b>	<b>\$13,415,091</b>	<b>Annual Total</b>	<b>276,000</b>	<b>71,462</b>



# Hourly, Monthly, Annual Generation Dispatch & Cost Analysis

Monthly Peak (MW) & Total (MWh) Solar Generation		
Month	Monthly MWh	Peak (MW)
January	5,155	33.9
February	5,825	39.4
March	7,107	42.7
April	7,678	43.7
May	8,371	42.8
June	8,168	42.7
July	8,906	43.7
August	8,753	43.9
September	7,440	43.3
October	6,337	39.4
November	5,340	36.9
December	4,890	34.6
Monthly Average	7,028	40.2
Annual Totals	84,249	

Monthly Peak (MW) & Total (MWh) Natural Gas Generation		
Month	Monthly MWh	Peak (MW)
January	20,435	40.5
February	18,648	40.5
March	18,648	40.5
April	18,399	40.5
May	18,242	40.5
June	18,362	40.5
July	20,476	40.5
August	20,908	40.5
September	18,796	40.5
October	20,828	40.5
November	18,594	40.5
December	18,999	40.5
Monthly Average	19,686	40.5
Annual Totals	236,232	



# Comprehensive Financial Analysis

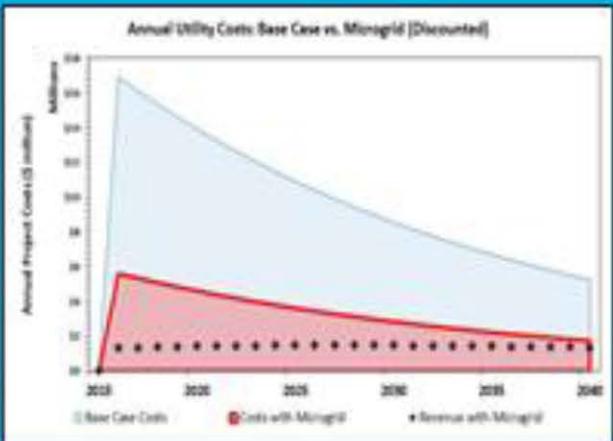
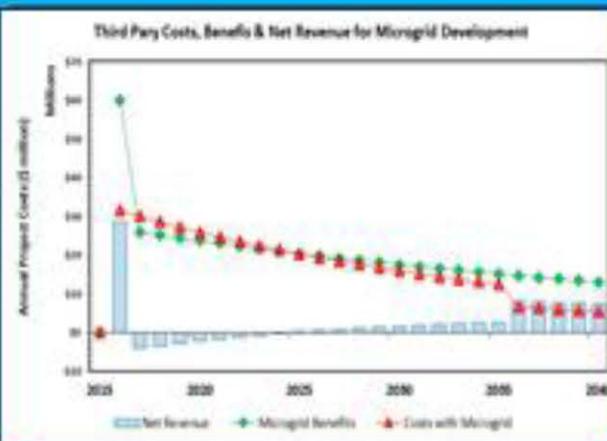
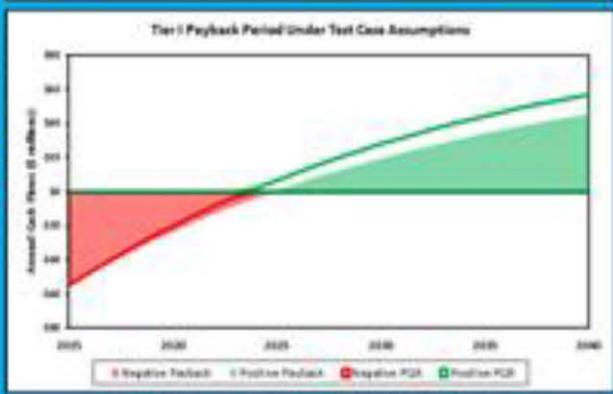
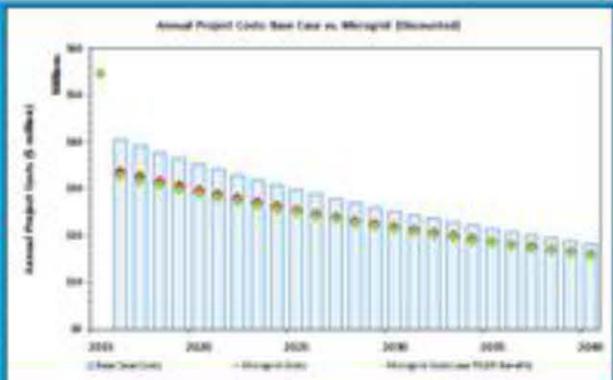
## Cash Flow, Payback Period, IRR, ROI

Cash Flow Analysis: Microgrid Customers (Tier 1)

Year	Original Energy Costs	Costs w/ MG	MG Payback
2015	\$1.0	\$1.0	\$0.0
2016	\$40.3	\$33.9	\$66.3
2017	\$39.2	\$33.9	\$65.9
2018	\$37.8	\$33.9	\$65.9
2019	\$36.4	\$33.9	\$65.9
2020	\$35.2	\$33.7	\$65.9
2021	\$34.2	\$33.8	\$65.9
2022	\$33.3	\$33.9	\$65.9
2023	\$32.4	\$33.8	\$65.9
2024	\$31.5	\$33.7	\$65.9
2025	\$30.8	\$33.5	\$65.9
2026	\$29.9	\$34.7	\$65.9
2027	\$29.0	\$33.9	\$65.9
2028	\$27.8	\$33.2	\$65.9
2029	\$26.5	\$32.3	\$65.9
2030	\$25.2	\$31.4	\$65.9
2031	\$24.4	\$31.7	\$65.9
2032	\$23.4	\$30.5	\$65.9
2033	\$22.4	\$29.9	\$65.9
2034	\$21.5	\$29.2	\$65.9
2035	\$20.4	\$28.7	\$65.9
2036	\$19.2	\$28.2	\$65.9
2037	\$18.0	\$27.4	\$65.9
2038	\$16.4	\$27.3	\$65.9
2039	\$14.8	\$26.6	\$65.9
2040	\$13.2	\$25.7	\$65.9

25 Year Totals

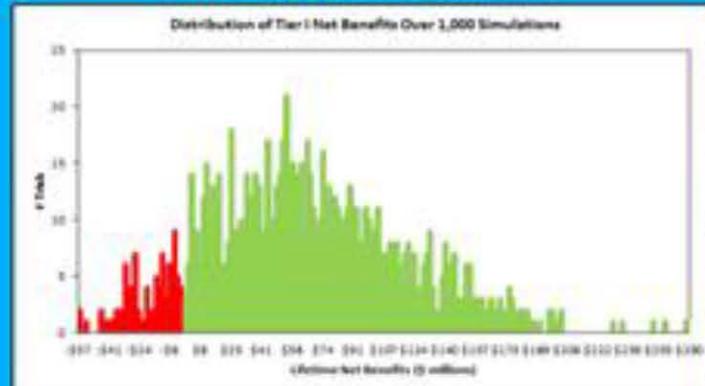
Year	2020	2025	2040
Original Energy Costs	\$35,343,460	\$25,243,343	\$14,350,740
Energy Costs w/ Microgrid	\$26,615,948	\$22,326,047	\$10,458,219
Financial Development Costs	\$0	\$0	\$0
Financial Benefits	-\$30,621,948	-\$22,326,047	-\$10,458,219
Benefits w/ PQ/Reliability	-\$30,621,948	-\$22,326,047	-\$10,458,219
Financial Cash Flow	-\$30,621,948	-\$22,326,047	-\$10,458,219
Cash Flow w/ PQ/Reliability	-\$30,621,948	-\$22,326,047	-\$10,458,219
Financial Payback Tracker	\$36,393,382	\$45,730,441	\$61,671,877
Payback Tracker w/ PQ/Reliability	\$36,393,382	\$45,730,441	\$61,671,877



# Monte Carlo Risk Analysis Module

## Analyze Variables Over 1,000 Trials

### Monte Carlo Analysis: Tier 1 Results



Monte Carlo Results: Percentile Distribution

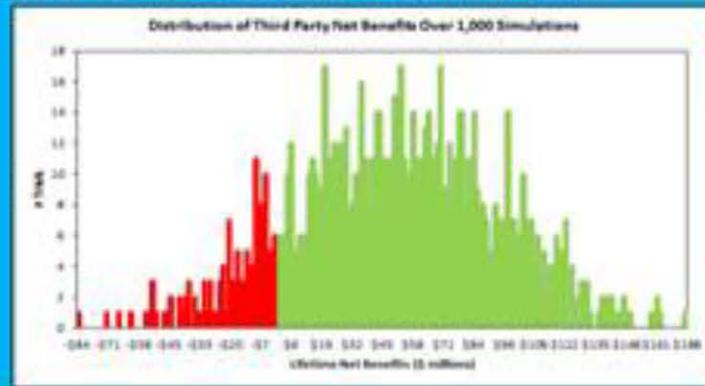
Monte Carlo Average	\$15,917,238
Monte Carlo Median	\$12,145,130
Monte Carlo Minimum	\$10,705,393
Monte Carlo Maximum	\$213,413,434
% with Positive Net Benefits	89.91%
10th Percentile	\$24,508,287
20th Percentile	\$16,485,781
30th Percentile	\$17,334,491
40th Percentile	\$226,505,824
50th Percentile	\$234,920,487

Over 1000 Variables

	Min	Max
CO2 Intensity (tons/kWh)	8.0000E	8.0000E
Solar Capacity Factor (%)	12.00%	16.00%
Wind Capacity Factor (%)	30.00%	30.00%
Single Capacity Factor (%)	41.64%	99.54%
NG Annual Price Change	75.00%	200.00%
Social Cost of Carbon	\$1.00	\$100.00
WACC Tax Rate	30.00	30.00
Demand Growth/Decline	50%	100%
Avg Rate Growth Factor	1.00	1.5000
Annual Power Quality Events	0	1
Annual Extinction Outages	0	1
Cost of PQ Events	\$1,100	\$10,000
Cost of Extinction Outages	\$12,500	\$100,000
Auxiliary Services	\$0.001	\$0.000
Fuel Hedging Value	\$0.0000	\$0.0001
O&M Deferred Costs	\$0.0000	\$0.0270
Capacity Deferred Costs	\$0.0000	\$0.0010
Battery O&M Costs	5%	11%
Discount Rate (%)	7%	10%
Inflation Rate (%)	1%	0%
Loan Interest Rate (%)	4%	6%
Subsage Value (% of Total Cost)	0%	100%
Total Capital Cost	5%	11%
REC Prices (\$/MWh)	\$1.00	\$10.00
SO2 Intensity (tons/kWh)	1,100-17	1,118-26
SOx Intensity (tons/kWh)	4,000-17	8,000-17
SO2 Allowance Price (\$/ton)	\$1.00	\$2.00
SOx Allowance Price (\$/ton)	\$0.00	\$100.00
SO2 Health Cost (\$/ton)	\$100	\$4,000
SOx Health Cost (\$/ton)	\$100	\$4,000
Integration/Adverse Cost	\$0.0000	\$0.0000

Distribution of Variables: **Normal**

### Monte Carlo Sensitivity Analysis: Third Party Developer



Monte Carlo Results: Percentile Distribution

Monte Carlo Average	\$50,905,954
Monte Carlo Median	\$51,113,494
Monte Carlo Minimum	\$40,850,112
Monte Carlo Maximum	\$176,172,176
% with Positive Net Benefits	89.11%
10th Percentile	\$70,876,911
20th Percentile	\$48,743,144
30th Percentile	\$77,328,444
40th Percentile	\$106,215,104
50th Percentile	\$118,411,088

Over 1000 Variables

	Min	Max
CO2 Intensity (tons/kWh)	8.0000E	8.0000E
Solar Capacity Factor (%)	12.00%	16.00%
Wind Capacity Factor (%)	30.00%	30.00%
Single Capacity Factor (%)	41.64%	99.54%
NG Annual Price Change	75.00%	200.00%
Social Cost of Carbon	\$1.00	\$100.00
WACC Tax Rate	30.00	30.00
Demand Growth/Decline	50%	100%
Avg Rate Growth Factor	1.00	1.5000
Annual Power Quality Events	0	1
Annual Extinction Outages	0	1
Cost of PQ Events	\$1,100	\$10,000
Cost of Extinction Outages	\$12,500	\$100,000
Auxiliary Services	\$0.001	\$0.000
Fuel Hedging Value	\$0.0000	\$0.0001
O&M Deferred Costs	\$0.0000	\$0.0270
Capacity Deferred Costs	\$0.0000	\$0.0010
Battery O&M Costs	5%	11%
Discount Rate (%)	7%	10%
Inflation Rate (%)	1%	0%
Loan Interest Rate (%)	4%	6%
Subsage Value (% of Total Cost)	0%	100%
Total Capital Cost	5%	11%
REC Prices (\$/MWh)	\$1.00	\$10.00
SO2 Intensity (tons/kWh)	1,100-17	1,118-26
SOx Intensity (tons/kWh)	4,000-17	8,000-17
SO2 Allowance Price (\$/ton)	\$1.00	\$2.00
SOx Allowance Price (\$/ton)	\$0.00	\$100.00
SO2 Health Cost (\$/ton)	\$100	\$4,000
SOx Health Cost (\$/ton)	\$100	\$4,000
Integration/Adverse Cost	\$0.0000	\$0.0000

Distribution of Variables: **Normal**

# Analyze Impact on Utility Revenue Electricity Rates & Lifetime Benefits

