



Solar + Storage

Reducing Barriers through Cost-optimization and Market Characterization

Modeling Input Values and Assumptions

October 26, 2016 (updated)

This presentation details the inputs and methodology that NREL is using to model economic and operational considerations for distributed commercial-scale solar + storage projects for regions across the U.S, using NREL's Renewable Energy Optimization model (REopt).

This methodology is considered a DRAFT and is still in development.

Please send questions and comments to joyce.mclaren@nrel.gov

Solar-plus-Storage: Cost Reductions through Optimization and Market Characterization

PROJECT SUMMARY

Through data collection, innovative modeling and analysis this project:

- Develops project cost baselines to refine modeling inputs based on current market data
- Identifies cost-optimal technology combinations of solar and storage for a variety of building types and market conditions
- Explores methods to value the contribution of solar-plus-storage to electric system resiliency
- Characterizes market potential for multiple technology and policy trajectories
- Supports identification of policy and regulatory options to support solar-plus-storage deployment

Final results available autumn 2017.

Project Website: http://www.cleanegroup.org/ceg-projects/solar-storage-optimization/

QUESTIONS ADDRESSED

- *At what technology costs are projects economical?*
- *What policy changes would encourage the formation of new markets?*
- *How can system owners capture multiple value streams?*
- *How can we value energy resiliency in economic calculations?*
- *Where will solar with storage be cost-effective in the near-term? Longer-term?*

Methodology considers different:

- Building Types
- Ownership Models
- End-Use Cases
- Utility Rate Tariffs
- Technology Costs
- Electricity Markets
- Incentives/Policies
- Climate Zones

VALUE STREAMS CONSIDERED

- ✧ Demand charge reduction
- ✧ Energy arbitrage
- ✧ Regulation/Capacity
- ✧ Demand Response
- ✧ Resiliency

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Methodology

This methodology is still in development as of October 2016.
Send comments to: joyce.mclaren@nrel.gov

Base Case & List of Sensitivity Analyses

Base Case	Cost savings from demand charge reduction and arbitrage only; 30% ITC and 5 year MACRS taken. (This base case is conducted for different technology costs, rates, locations, load profiles, ownership structures. See details in following slides.)
NEM Case	Base case + NEM at the retail rate w/ system size capped at 100% of load
NEM 2.0	Base case + sellback compensation/credit at the wholesale rate w/system size capped at 100% of load
Frequency Regulation	Base case + frequency regulation payment(s)
Capacity	Base case + capacity payment(s)
Demand Response	Base case + demand response payment(s)
ITC	Test impact of step-down of ITC to 10% and 0%. Possible test of impact of allowing up to 25% grid charging and taking reduced ITC.
Retail Electricity Price CAGR 2016-2036	Base Case 0.39% (EIA Reference Case) Sensitivities: High Fossil Resource 0.02% ; High Fossil Fuel Prices 0.69%
Age and size of Building Stock	Base case uses 1980s DOE Reference Buildings. This sensitivity analysis tests the impact of the age and size of the building on results.
Valuing Resiliency	Base case + assigning a value for resiliency
Load Profile: Hourly vs. 15 min. (time allowing)	15 min. load profiles will be used to test the sensitivity of the results to the use of 15 min. vs. hourly load data. All other data (e.g. weather data) remains hourly.

Summary of Proposed Modeling Input Assumptions

Input/Variable	Base Case	Sensitivity Analyses
Project Locations	16 ASHRAE Climate Zones	
Load Profiles/Building Types	DOE commercial reference buildings, 1980's stock	New construction; pre-1980s construction
Utility Rate Structures	80+ commercial rates incl. basic, demand charge, TOU, experimental rates	
Analysis Period	20 years; 2017-2037	
Inflation Rate	2.5%	
Elec Cost CAGR	0.39% (EIA reference case)	0.02% (High Fossil Resource) 0.69% (High Fossil Fuel Prices)
Real Discount Rate	10.2%	
ITC	30% for PV and storage components	ITC step-down to 10% and 0% Possible analysis of reduced ITC due to grid charging
MACRS for PV	5 year + bonus depreciation	
MACRS for storage	5 year+bonus depreciation	If battery charges >25% from grid: 7 year depreciation
Net metering	No net metering	Retail rate w/ size capped at 100% load; Wholesale rate w/size capped at 100% of load
Frequency Regulation Payment		Based on PJM market (please comment on value/method)
Demand Response Payment		$30/kW of reduction
Capacity Payment		$30/kW
Value of Resiliency		Average of ACI based on LBNL, 2013

Financial Assumptions and PV costs for REopt modeling are in line with NREL Annual Technology Baseline (2016)

Financial Assumptions:	
Inflation Rate	2.5%
Economic Lifetime (Years)	20
InteCommt Rate - Nominal	8.0%
Calculated Interest Rate - Real	5.4%
Interest During Construction - Nominal	8.0%
Customer Equity Discount Rate - Nominal	13.0%
Calculated Equity Discount Rate - Real	10.2%
Debt Fraction	60.0%
Tax Rate (Federal and State)	40.0%
WACC - Nominal	8.1%
WACC - Real	5.4%
Depreciation Period	5
Construction Finance Factor	1.024
Present Value of Depreciation	0.810
Project Finance Factor	1.127
Capital Recovery Factor (CRF) - Nominal	10.2%
Capital Recovery Factor (CRF) - Real	8.3%

Construction Duration yrs		1
Year Index	Capital Fraction	Accumulated Interest
0	100%	1.024
1	0%	1.073
2	0%	1.127

MACRS yr	1	2	3	4	5	6
Depreciation Fraction	0.2000	0.3200	0.1920	0.1152	0.1152	0.0576
Depreciation Factor	0.9252	0.8561	0.7921	0.7329	0.6781	0.6274

Investment Tax Credit (ITC)*	0.0%
Production Tax Credit (PTC)*	0.0%

* not currently included in LCOE calculation

NREL (National Renewable Energy Laboratory). 2016 Annual Technology Baseline (ATB). Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html

Proposed Modeling Battery Input Assumptions

Variable	Value(s)
Inverter & Storage Replacement	In Year 10
Total Round Trip Efficiency	82.9%
Battery Throughput	85%
Inverter Efficiency	92%
Rectifier Efficiency	90%
Minimum Charge	20%
Initial State of Charge	50%

Project components included in the REopt modeling cost assumptions

Battery & Hardware

- Battery
- Inverter - Power Conversion
- Container or Housing
- Container extras (Insulation/Walls)
- Electrical Conduit (Inside of container)
- Communication Device
- HVAC
- Meter (Revenue Grade)
- Fire Detection
- Fire Suppression
- Labor
- AC Main Panel
- DC disconnect
- Isolation Transformer
- AUX Power - lighting etc

Soft Costs

- Developer Cost (Customer Acquisition)
- Interconnection

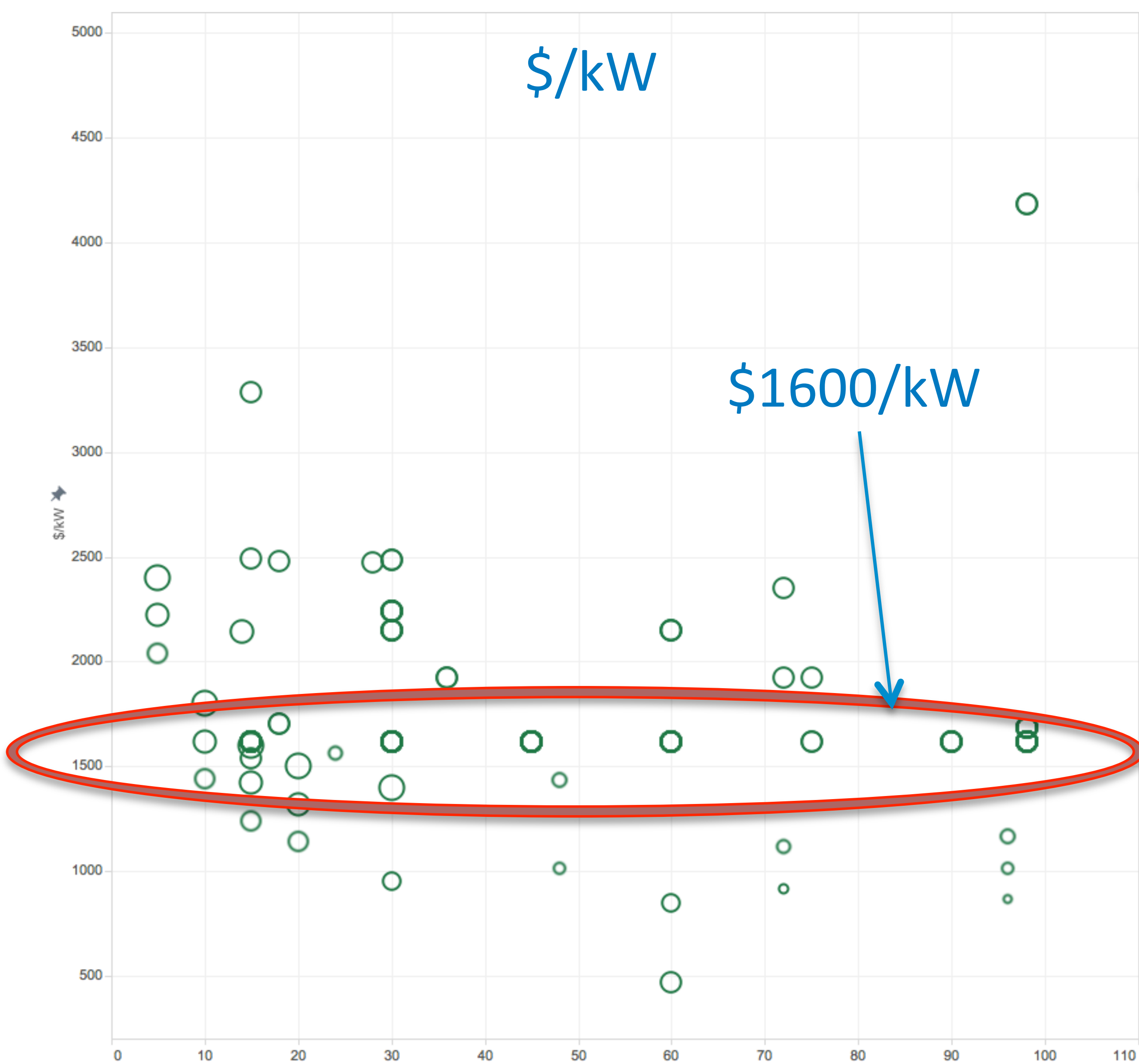
EPC

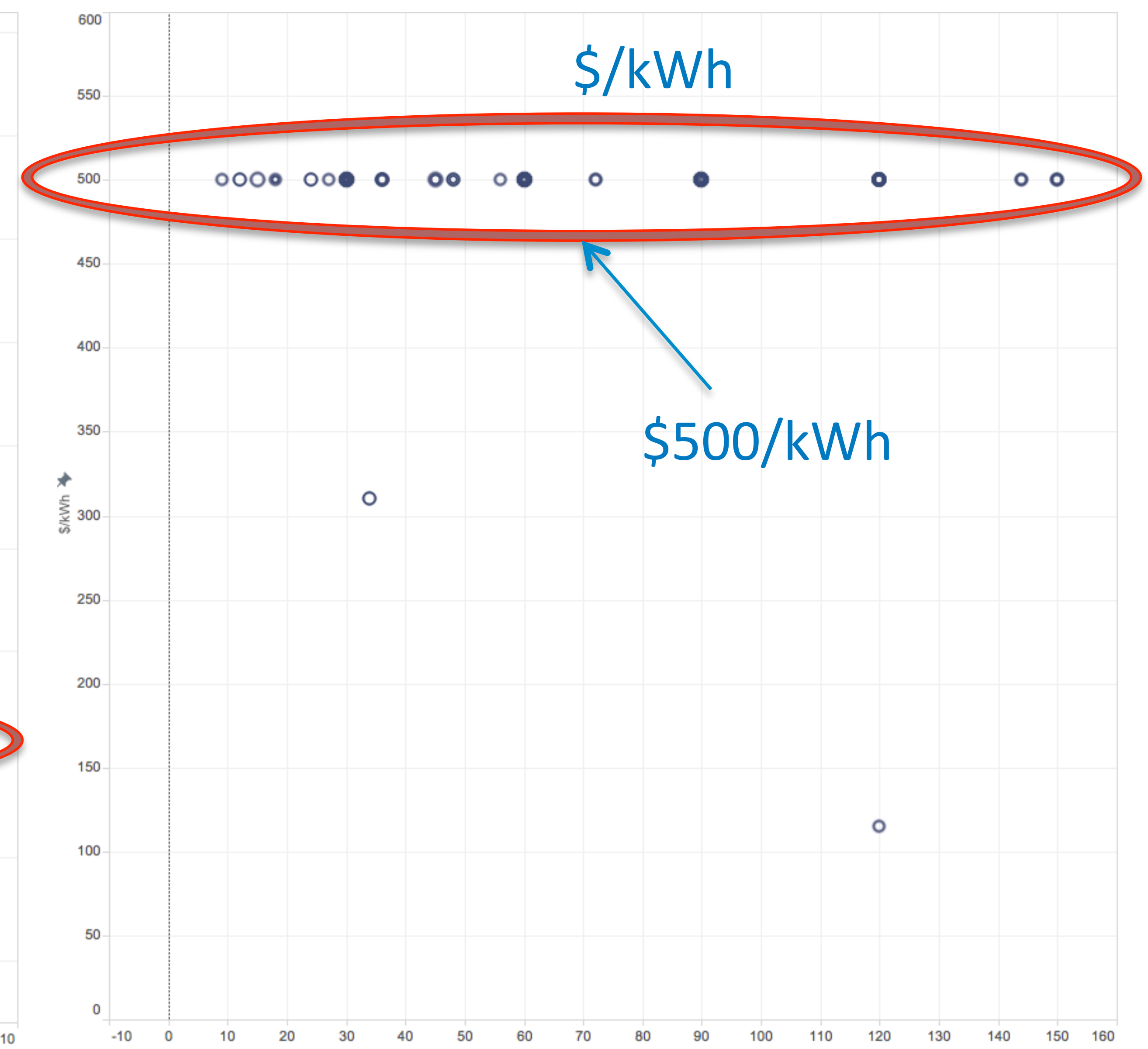
- Control System/SCADA
- Site Preparation
- Loading & Drive from OEM site
- Lifting & Hoisting by crane on site
- PE stamped calcs & drawings
- OEM testing and commissioning
- Electrical BOS outside of container (Conduit, wiring, DC cable)
- Electrical Labor
- Structural BOS (fencing)
- EPC Overhead & Profit

Basis for storage project cost assumptions

$/kW + $/kWh = total project cost

The REopt model requires separation of $/kW and $/kWh. Storage costs are not typically reported in this manner. The proposed storage cost inputs for the base case were informed by conversations with multiple industry participants. The graphs below show the values for projects where data was made available.





PV & Storage Cost Assumptions

	Base Case	High Cost Case	Cost Reduction Case A	Cost Reduction Case B
PV Cost Total (Hardware+EPC)	$2.05[1]	$2.25[2]	$1.53[3]	$ 1.42[4]
PV O&M cost (includes inverter replacement)	$12.60/kW-yr.[1]	$15/kw-yr.[2]	$10/kW-yr[3]	$10/kW-yr.[4]
Storage Cost	$1600 /kW[5] $ 500 /kWh	+20%	-20%	-50%
Storage replacement cost (in year 10)	$200/kW $200/kWh	+20%	-20%	-50%

[1-4] NREL (National Renewable Energy Laboratory). 2016 Annual Technology Baseline (ATB). Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html

[1] ATB average for 2017

[2] ATB highest for 2017

[3] ATB average for 2027

[4] ATB average for 2037

[5] Storage cost breakdown based on project cost data collected by NREL.

Load profiles: DOE Commercial Reference Buildings

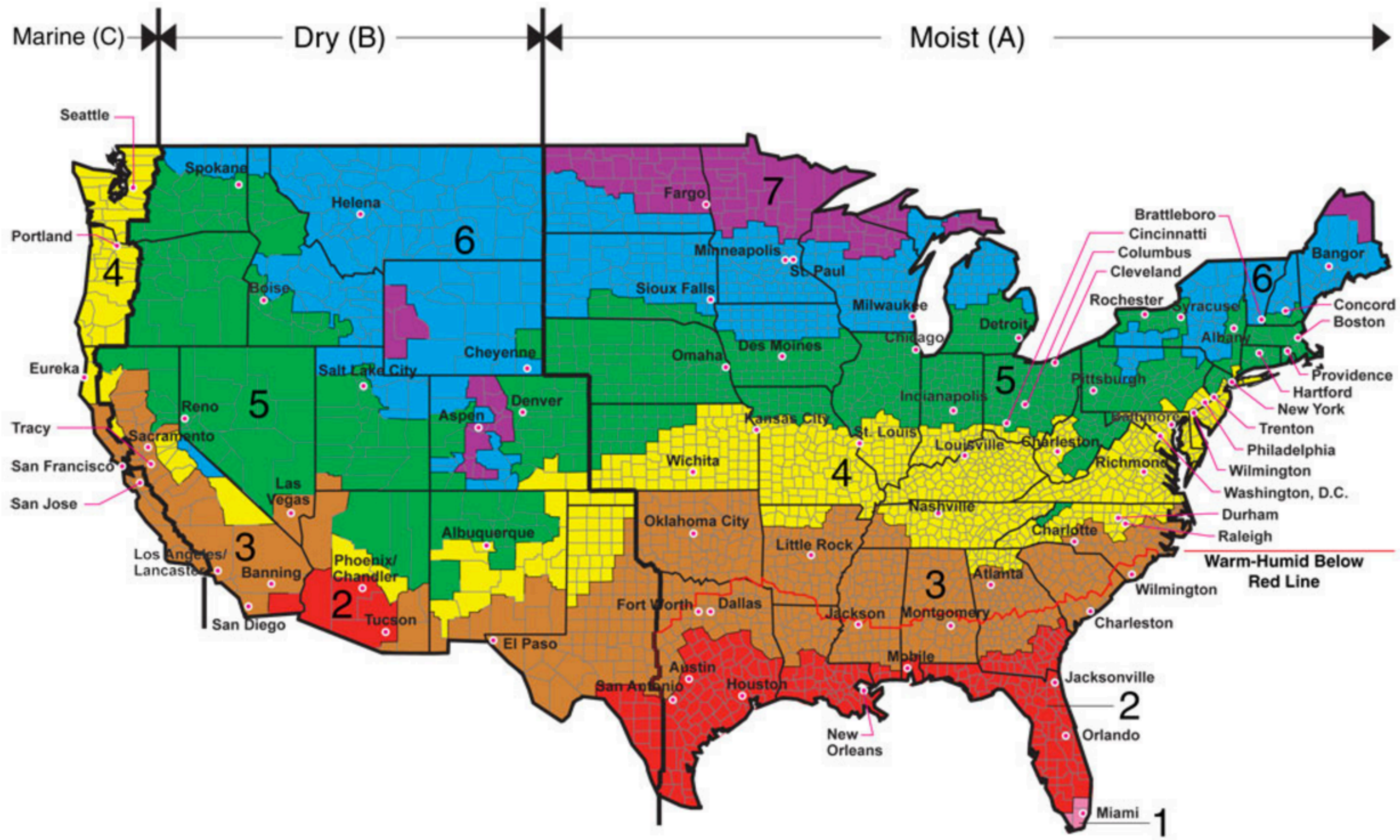
- Primary School
- Secondary School
- Outpatient Health Care
- Hospital
- Midrise Apartment
- Full Service Restaurant
- Large Hotel
- Small Hotel
- Quick Service Restaurant
- Stand-alone retail
- Supermarket
- Warehouse
- Large office
- Medium office
- Small office
- Strip mall

Method used to select rates to model

- We identified the utilities with largest number of commercial customers in each climate zone based on EIA data "sales and customers per utility".
- We have updated each commercial rate for the selected utilities in NREL's Utility Rate Database
- We will model at least one TOU and Demand Charge rate in each location, as well as some existing unique/experimental rate structures.
- We will identify the potential for customer bill reduction for each rate structure/building load.
- When escalating rates, we will increase each rate component by the same percent (e.g. we are not re-designing/re-weighting rates)

16 ASHRAE Climate Zones are represented in modeling

ASHRAE CLIMATE ZONE MAP



All of Alaska in Zone 7 except for the following Boroughs in Zone 8: Bethel, Dellingham, Fairbanks, N. Star, Nome North Slope, Northwest Arctic, Southeast Fairbanks, Wade Hampton, and Yukon-Koyukuk

Zone 1 includes: Hawaii, Guam, Puerto Rico, and the Virgin Islands

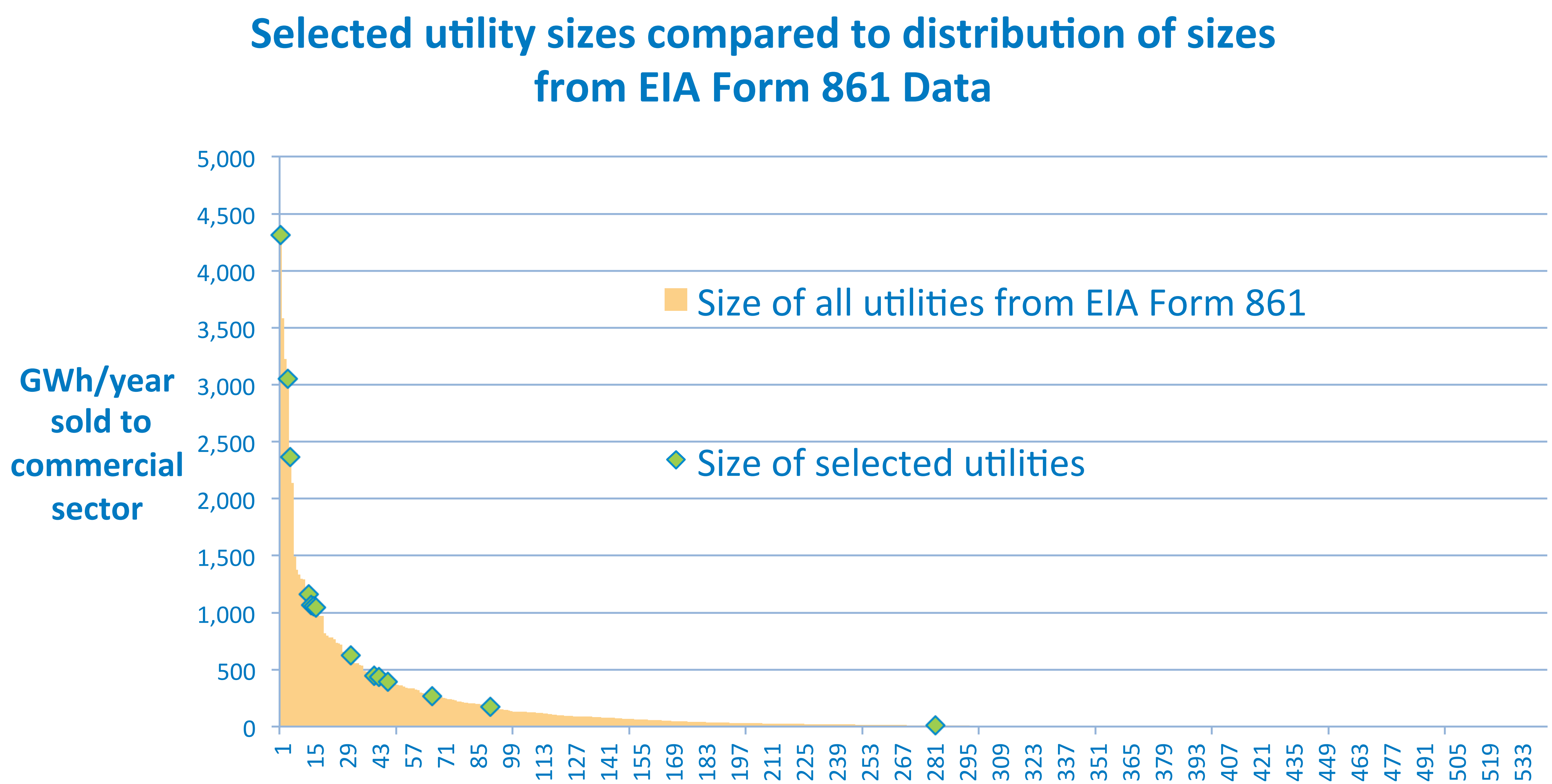
Representative Utilities

The utility with largest number of commercial customers in each climate zone was identified. Some climate zones are represented by multiple utilities. We model all commercial rates applicable for each building type.

Utility Name	Climate Zone	Representative City	Sales to commercial sector (MWh)
Florida Power & Light Co	1A	Miami, Florida	4,316,495
Centerpoint Energy for Delivery, Reliant Energy for Power (deregulated)	2A	Houston, Texas	No EIA Form 861 data
Salt River Project	2B	Phoenix, Arizona	1,055,677
Georgia power company	3A	Atlanta, Georgia	3,053,786
Los Angeles Department of Water & Power	3B-Coast	Los Angeles, California	1,045,721
Southern California Edison	3B-Coast	Bakersfield, CA	39,593,000
NV Energy (Nevada Power)	3B	Las Vegas, Nevada	434,855
Pacific Gas & Electric	3C	San Francisco, California	2,365,500
Baltimore gas and electric	4A	Baltimore, Maryland	169,978
Con Edison	4A	New York, New York	42,858,551
Public Service Company of NM	4B	Albuquerque, New Mexico	393,132
City of Seattle	4C	Seattle, Washington	445,585
Commonwealth edison	5A	Chicago, Illinois	623,588
Xcel Energy (Public Service Co. of Colorado)	5B	Boulder, Colorado	1,068,445
Xcel Energy (Northern States Power Company)	6A	Minneapolis, Minnesota	1,158,937
NorthWestern Energy Service	6B	Helena, Montana	267,802
Minnesota Power	7	Duluth, Minnesota	No EIA Form 861 data
Golden Valley Electric Association	8	Fairbanks, Alaska	9,160

Utilities are representative of all U.S. utilities

This graphic indicates the spread of utility sizes that are represented.



Unique rate structures are examined more closely

Note that these tariffs are not intended to be a representative set (by geography, customer type, or structure). They have been chosen for individual analysis because they are unique and might reveal interesting opportunities for S+S.

Utility	Tariff(s)
Salt River Project	Experimental price plan for super peak TOU general service
Minnesota Power	Commercial controlled access service
PG&E and SCE	Peak day pricing and Capacity bidding program
Xcel Energy (Minnesota)	Real time pricing
ConEdison	Standby tariff SC9-Rate4 may incentivize a flatter load

Sensitivity Analyses:

ITC step-down

Net Metering

Ancillary Services

Escalation Rate

Age of Building Stock

15-minute load profile

Value of Resiliency

Net Metering & NEM 2.0 Sensitivity Analyses

- Base Case assumes *no net metering or sellback rate*
- Why does the Base Case not include Net Metering:
  - The future of net metering policies is uncertain
  - Net metering does not exist in some utility territories
  - System owners may prevent power injections to ensure the ability to receive the Investment Tax Credit
  - Many commercial S+S installations have sufficient load to absorb all self-generated power
  - Adding storage to solar installations sometimes negates the value of net metering to the system owner
- Two Net Metering Sensitivity cases:

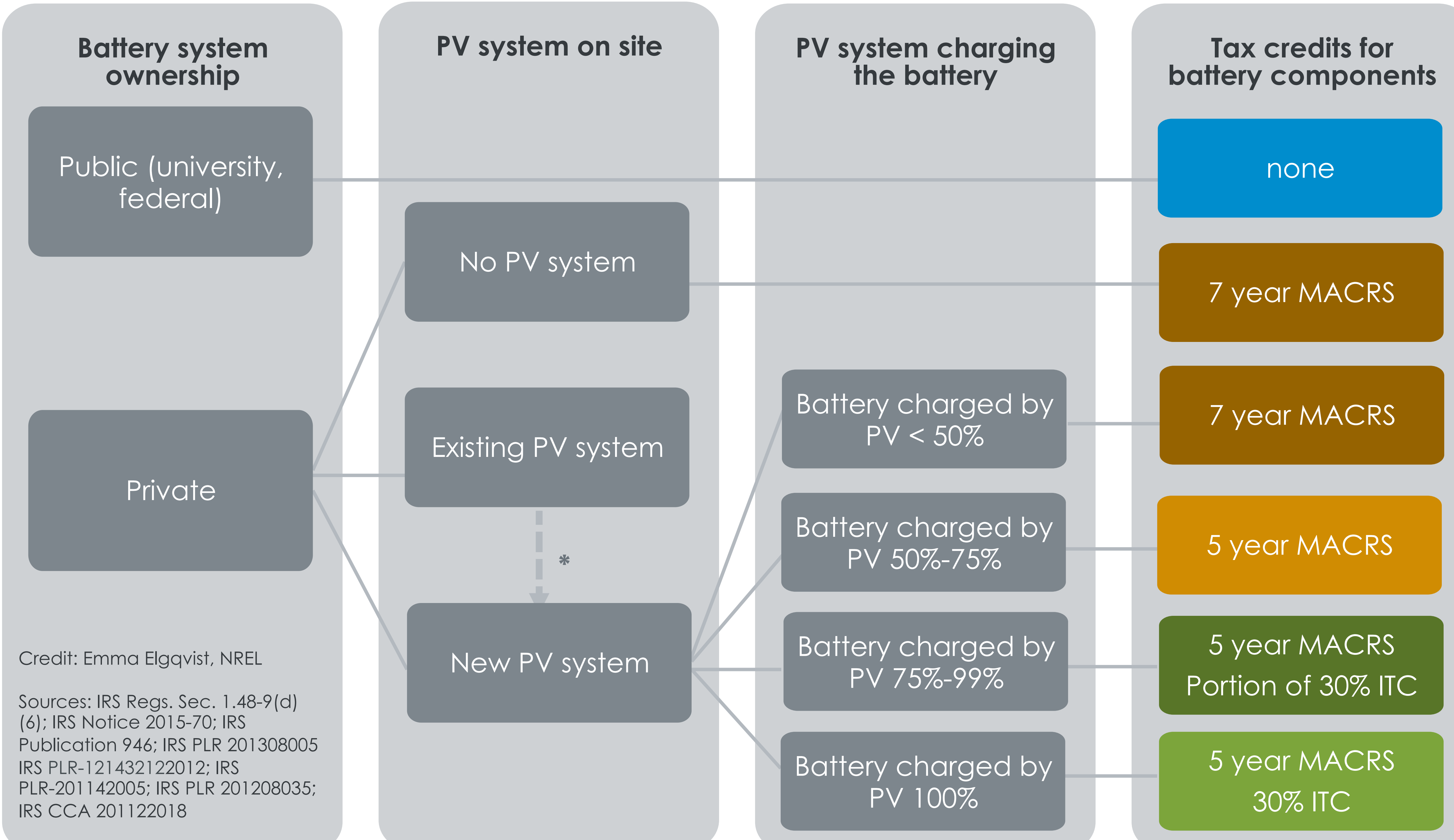
  (1) net metering at retail rate

  (2) the wholesale rate

  Both cases have system size capped at 100% of load

ITC & MACRS for solar and storage projects

The Investment Tax Credit (ITC) and Modified Accelerated Cost Recovery System (MACRS) are national level incentives that can improve battery energy storage project economics.



Credit: Emma Elgqvist, NREL

Sources: IRS Regs. Sec. 1.48-9(d)(6); IRS Notice 2015-70; IRS Publication 946; IRS PLR 201308005 IRS PLR-121432122012; IRS PLR-201142005; IRS PLR 201208035; IRS CCA 201122018

*We assume energy storage can be added to an existing PV system based on precedents set by a IRS Private Letter Ruling that allowed owner of a wind turbine to add energy storage to existing facility and claim the tax benefit. We believe that the PV and energy storage would need to be in close proximity and under common ownership (same taxpayer). We believe a replacement battery (e.g. at 10 years) does not qualify for the ITC, but does qualify for 5 year MACRS.

How the ITC and MACRS is handled in the modeling

- Interviews with S+S developers indicate that in some cases controllers are being used to prevent charging from grid to ensure that the storage qualifies for the ITC.
- In our base case, the battery is forced to charge only from the PV (no grid-charging) and takes the full ITC and 5 year MACRS.
- This is a simplifying assumption since technically an owner could allow up to 25% grid charging and take a reduced ITC.
- A case study or sensitivity analysis can be conducted (if deemed appropriate) to investigate the economic impact of allowing up to 25% grid charging with reduced ITC taken.
- Two additional sensitive analyses will be conducted to understand the impact of a future step-down of the ITC to 10% and 0%.
- *Possibly model the impact of the new bill S. 3159 - introduced to make energy storage eligible for an investment tax credit (ITC) under section 48. (More info here.)*

Providing Ancillary Services: Sensitivity Analysis

- Storage is currently participating in ancillary service markets in PJM and CAISO territories.
- Payments for ancillary services greatly impact S+S project economics in the regions where markets exist.
- Our base case will NOT include payments from ancillary services (this allows us to determine the circumstances under which demand charge reduction/TOU arbitrage alone make projects economical).
- We will do sensitivity analyses to determine the impact of:
  - Frequency regulation payments
  - Capacity (Demand Response) payments
- See slides below for proposed methods/values.
- We are still taking comments on appropriate input values.

Payments for Capacity/Demand Response: Sensitivity Analysis

- BTM storage provides demand response by dispatching capacity in response to events defined by the ISO/utility
- Broadly speaking, DR is provided in one of 3 ways:
  - Dispatched Curtailment – customer agrees to the remote dispatch of the capacity by the system operator
  - Mandatory Curtailment - customer bids into market to provide service and is required to dispatch if selected
  - Voluntary Curtailment – customer decides whether to provide service
- Demand response programs appear to be simplifying, with a consolidation of products/programs that storage can choose to participate in.
- Programs can broadly be categorized as:
  - Pre-scheduled
  - Real-time

Payments for Capacity/Demand Response: Sensitivity Analysis

Both pre-scheduled and real-time capacity/demand response markets/products may be modeled:

- Method: Pre-schedule DR program
  - Storage receives a $/kW payment for providing capacity/demand response for a 4 hour window on the hottest 12 days of the year.
    - Method intended to represent participation in a demand response program similar to those commonly offered by utilities in California
    - Method is similar to PJM's Emergency Load Response product
    - The $/kW payment will be based on best available information of currently published DR payments
    - Method will be applied in every utility region being modeled
    - The $/kW payment value will be scaled up or down (%) for other utility regions, according to the total electricity cost in each region.
- Method: Real-time DR
  - $/kWh payment received for participation in real-time DR market through an aggregator (or self-aggregation)
  - Intended to represent existing California DRAM or PJM real-time DR markets
  - Payment based on best available data on CA DRAM or PJM DR market payments and scaled for regions that do not currently have real-time DR programs, based on cost of electricity/kWh under general commercial tariff.

Payments for Frequency Regulation: Sensitivity Analysis

Frequency Regulation (FR) payments will be investigated in every utility region being modeled, to represent impact of potential/future regulation markets

Proposed Method:

- Historical PJM signal for one year will be used to bound amount of FR requested during any hour
- Input into REopt a $/kWh payment that will be offered for providing frequency regulation during each hour of the day
  - $ amount will be based on historical PJM market data for PJM
  - $ amount based on the published energy transmission tariff in OASIS for other regions

Logic for this proxy: Providers typically purchase FR from a transmission owner. But if a battery can provide FR, the service could be purchased from a battery instead.

Electricity Escalation Rate: Sensitivity Analysis

- Elec Cost Escalation Rate is based on EIA
- http://www.eia.gov/forecasts/aeo/excel/fig-9_data.xls
- Base case assumes 0.39% CAGR over the study period 2016-2036.
- Sensitivity analysis will be conducted using alternate escalation rates:
  - High Fossil Resource = 0.02%
  - High Fossil Fuel Prices = 0.69%

Age and Size of Building Stock: Sensitivity Analysis

- Base case uses 1980s DOE Reference Buildings.
- Using the DOE Reference Building profiles for older and newer buildings, sensitivity tests will be run to understand the impact of the age of the building on results.
- The impact of increasing or decreasing the size of the building load will be examined for certain building types.

15-minute vs. hourly load profile

- 15 minute load profiles are being created by the NREL commercial building team
- Results using these (for a set of scenarios) will be compared with results from the base case to determine the sensitivity of the results to 15 minute profiles vs. hourly profiles.
- Base case retains hourly profiles because the granularity of data such as weather necessarily remains at the hourly level

Value of Resiliency: Sensitivity Analysis

The amount of resiliency provided by an S+S system is difficult to quantify.

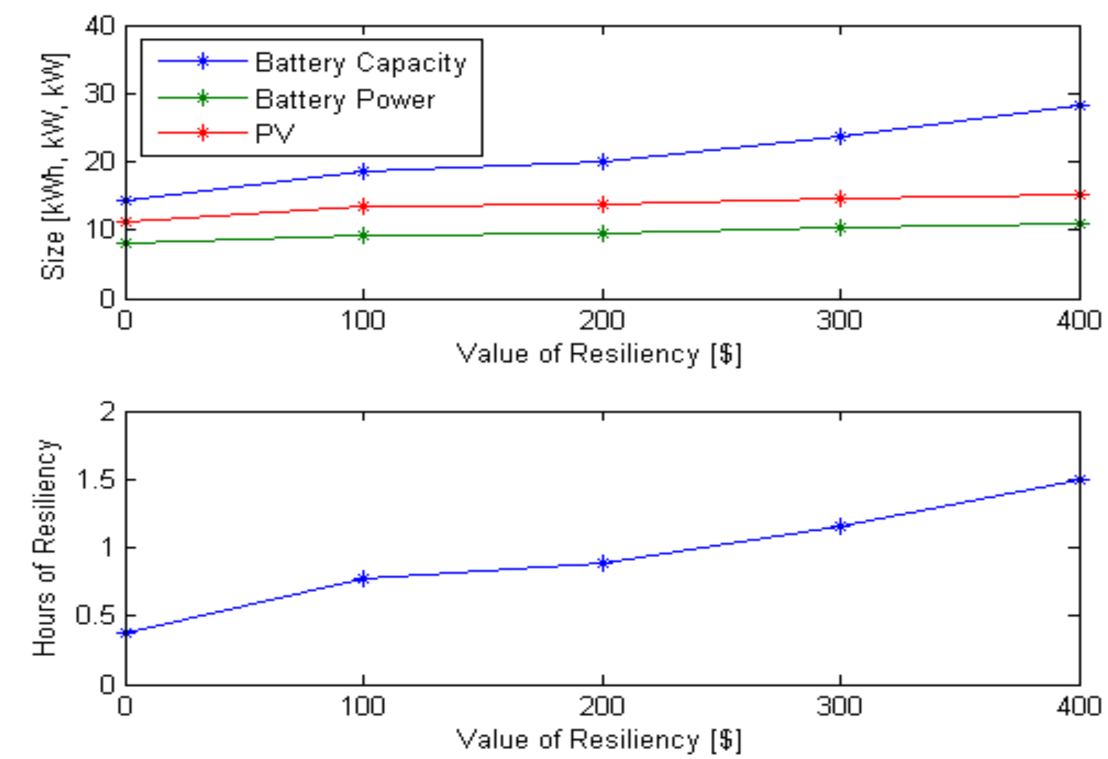
And is fundamentally different than that from a diesel generator, which provides power until fuel reserves are exhausted. Due to the uncertainty of resiliency from an S+S system, the value may be deemed lower.

Resiliency from S+S depends on the:

- Battery state of charge at time of outage
- Solar resource available during outage

However, the incremental value of resiliency from S+S could be enough to make a project economically viable.

We will model the impact of valuing resiliency by including a value for resiliency in the optimization.



As the value placed on resiliency increases, optimal system sizes and the number of hours a load is sustained will both increase.

Assigning a Value to Resiliency

Method: For each hour that a S+S project can sustain a given critical load (X% of the total load) during a grid outage, a value for this resiliency benefit is included in the optimization.

The proposed value of resiliency is the average cost and duration of grid outages (ACI), based on a 2013 LBNL report:

Table ES-1: Estimated Interruption Cost per Event, Average kW and Unserved kWh (U.S.2013$) by Duration and Customer Class

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

(2015) Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, Lawrence Berkeley National Laboratory, LBNL-6941E, http://eetd.lbl.gov/sites/all/files/lbnl-6941e_0.pdf

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http://www.cleanegroup.org/solar-storage-optimization/

www.nrel.gov

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