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E3 Solar + Storage Optimization Tool

Model User Guide & Documentation

May 16, 2019

Energy+Environmental Economics

E3 Solar + Storage Optimization Tool

Model User Guide & Documentation

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1 Introduction

This document provides the user guide and documentation for the Solar + Storage tool (the tool) funded by the CEC under the EPIC Program (EPC-17-004).

California is leading the nation in installed solar rooftop systems, and is home to a range of advanced technology companies designing and manufacturing battery storage, communicating controls, and electric vehicles that comprise the emerging “smart grid.” Solar is a great resource for California, but is already hitting limits on specific distribution systems with high penetration; the California ISO is seeing a future with so much solar that integration becomes a challenge. As the penetration of solar increases and technology costs decrease, opportunities will arise to increase the benefits of solar by shaping its output with battery storage and advanced controls on electrical consumption. To capture the value from these technologies, and to provide a stable long-term value proposition to accelerate their development and deployment, we should integrate the capabilities that these technologies provide into the planning and operations of the electricity grid.

This tool estimates the value proposition of the integrated solar and storage systems based on their expected optimal operations, location on the grid, market prices, and other characteristics. The tool also evaluates the operations of distributed solar + storage in combination with other controllable DER technologies such as smart thermostats, electric vehicle chargers, and similar devices. These combinatory scenarios provide insights on the synergy among multiple technologies and their integrated impacts on distribution deferral values and customers’ bills. In addition to the existing programs and revenue streams, the tool also provides great flexibility in evaluating future rates, demand response, and resource adequacy program designs.

The first half of the document is the user guide. It includes step by step case set-up instructions, as well as descriptions on the four UI in the model. The second half documents the underlying methodology for the tool, including relevant formulas.

2 User Guide

The tool is built in Python but has Excel user interfaces that provide intuitive platforms for generating inputs, setting up cases, and viewing results. The users don't need to have Python knowledge to use the tool. As shown in the Figure 2-1 below, the core optimization and calculation engine are built in Python, an open-source and increasingly popular programming language. Inputs and outputs that are directly coming in and out of Python are in .csv formats and are saved in the cases and data folders. Four UIs are interacting with .csv files by savings them from the UI and reading in .csv files. The Inputs Generator and Dashboard provide UI access to the full set of features, and the Solar + Storage Simplified UI and Distribution Values Screening UI provide simplified set-up with targeted use cases and limited features. The four UIs are summarized below:

+ **Inputs Generator UI**

  The input interface to save all model required inputs into data folders in .csv formats.

+ **Dashboard UI**

  The main user interface to set up cases, execute Python code, and interpret/display results.

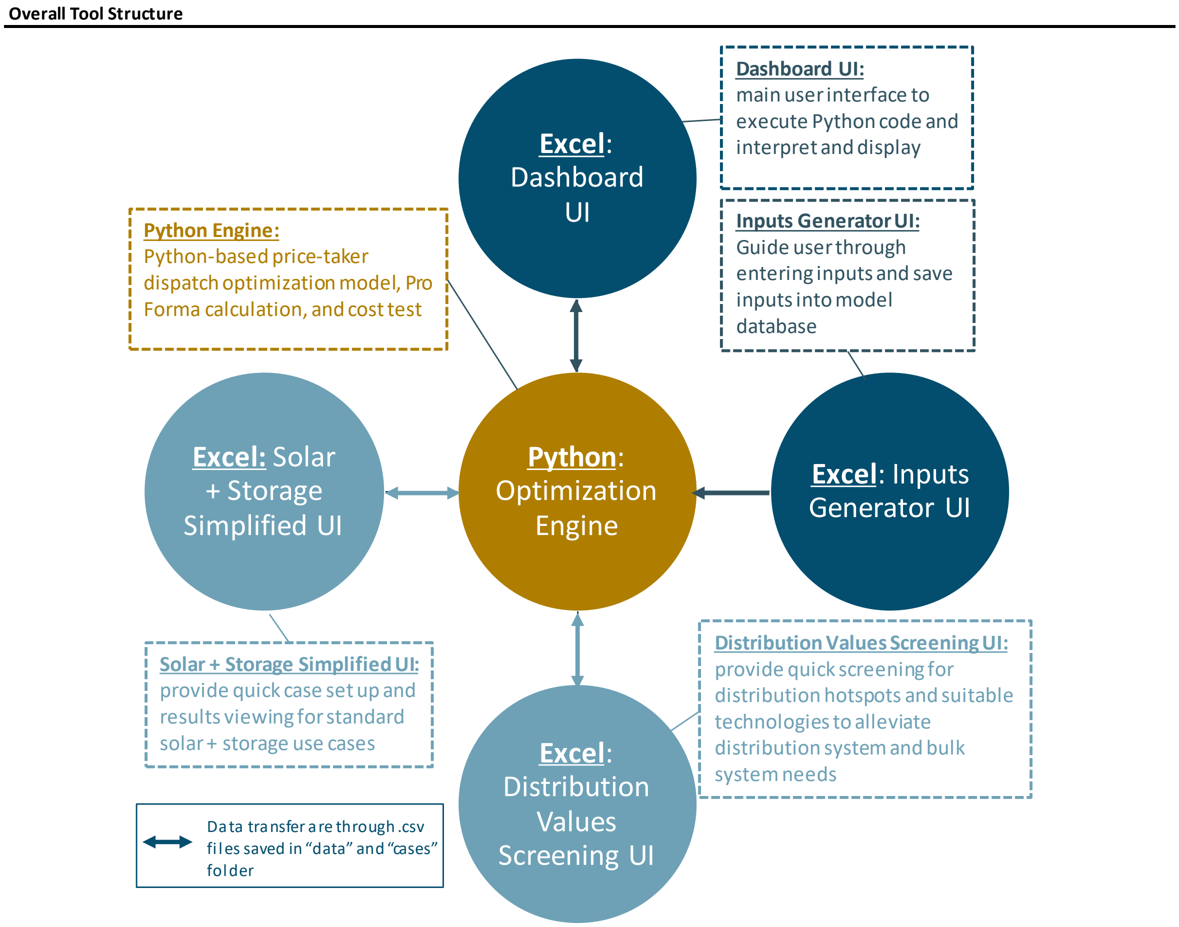
+ **Solar + Storage Simplified UI**

  The interface that provides quick case set-up and results viewing for standard solar + storage use cases.

+ **Distribution Values Screening UI**

  The interface that provides quick screening for distribution hotspots and suitable technologies to alleviate distribution system and bulk system needs.

Figure 2-1 Model Structure Overview



Four cases with different use cases are run and loaded in the model as examples. Users can load in the example cases into corresponding UIs to examine the results and see the kinds of analysis the tool can offer. The instructions on loading cases in the Dashboard UI is in Chapter 23. The four example cases are:

+ *Solar + Storage Simplified UI*: **BTM Bill Savings**

A BTM project with a 10 kW PV and a 5 kW 4-hour battery. This project provides bill savings and reliability values to a commercial customer

+ *Solar + Storage Simplified UI*: **FTM Wholesale Market Participation**

  An FTM project with a 1 MW PV and a 200 kW 2-hour battery. The revenue streams include energy arbitrage, resource adequacy payment (50kW participation), and ancillary service revenues

+ *Dashboard UI:* **Non-wires Alternative Evaluation**

  Estimating the opportunity of deferring a $2 million distribution investment by the NWA project consist of a 200 kW PV, a 200 kW 2-hour battery, and Lighting and HVAC energy efficiency measures. The additional revenue streams include energy arbitrage, resource adequacy payment (20 kW capacity), and ancillary service revenues

+ *Distribution Values Screening UI*: **Technology Screening**

  This example summarizes the system values including distribution avoided costs provided by each DER technologies with generic characteristics assumptions.

+ *Dashboard UI*: **Smart Home Operation**

  A commercial customer owns the following DERs: PV, storage, EV, energy efficiency measures, fuel cell generator, smart water heater, and smart HVAC system. The model is optimized to figure out the cheapest operating schedule for these devices to meet customer's need. Noted the parameters for smart water heater, smart HVAC system, and fuel cell generator are placeholders. Actual parameters might vary significantly based on the hosts.

This chapter starts with an overview of the model structure and is followed by a quick-start guide to walk through how to set up a case and make your first model run. Chapters 2.2 to 2.5 provide in-depth descriptions for the tabs in the four Excel interfaces.

Many screenshots of the UIs are included in this document. To provide user an easy reference, the figure titles of screenshots are labeled in the same format: "[UI name]/[Tab name]: Figure title".

2.1 Case Setup Overview

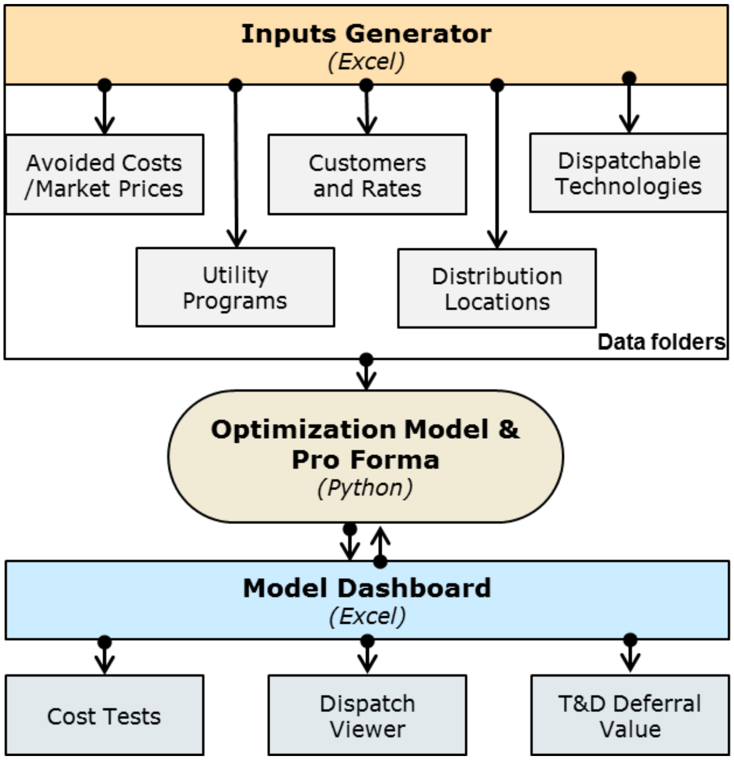
2.1.1 STANDARD CASE SETUP

This section will provide an illustrative walk-through walkthrough and an outline of necessary inputs for the user to set up a working case from scratch.

The first part of this section introduces how to set up a case with the existing inputs in the model database. The model comes with some default data for California, including avoided costs, historical wholesale DA energy prices, ancillary services prices, representative rates, and customer load shapes for three IOUs. Users can use those data to get started on creating cases. Case creation and results viewing are in "Model Dashboard.xlsb."

For users who have spent some time with the model and would like to use their data for a specific project, the second half of this section describes how to create your own inputs and save them in the database. Users interact with "Inputs Generator.xlsb" when creating new inputs.

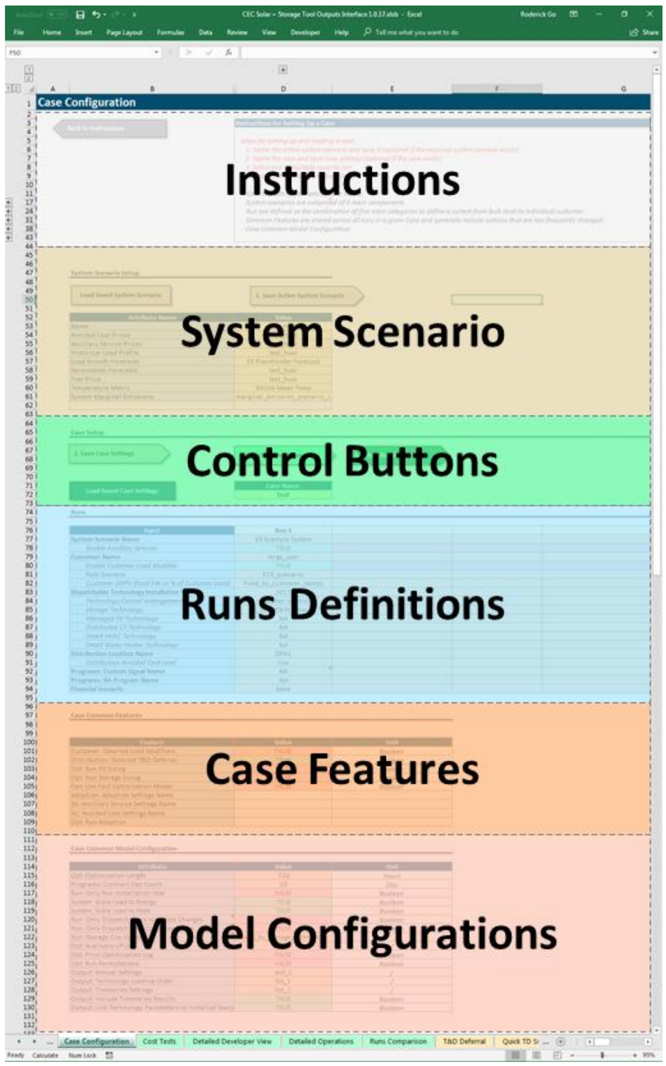
Figure 2-2 Standard Case Setup Workflow



2.1.1.1 Model Dashboard: Creating and Running a Case

To create a case for the model, case configurations must first be set up and the user must input the necessary information outlined below.

Figure 2-3 Model Dashboard/0. Case Configuration: Tab Overview



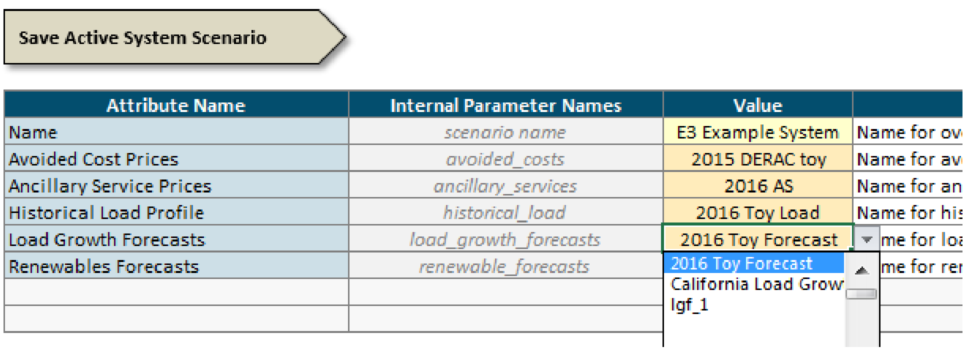
On the ***0. Case Configuration*** tab of the "Model Dashboard" spreadsheet, users will find several subsections. These subsections can be grouped into two main sections:

- System scenario setup
- Case configuration

In both Model Dashboard and Inputs Generator, detailed descriptions for inputs show up when you hover the mouse over either the input name or the input cell.

The system scenario setup defines the underlying combination of assumptions that a user would like to save under a given name. For example, the Solar + Storage Tool includes data for an “E3 Example System”, which includes assumptions of California load and avoided cost forecasts.

Figure 2-4 Model Dashboard/0. Case Configuration: Selecting the saved components that comprise a system scenario



The case configuration is made up of four components:

- Case name
- Run definitions in case
- Case common features
- Common model configuration options

For each new case, the user defines a case name and uses the dropdown cells to define the combination of bulk system, locational, customer, technology, and financial data to include for each run in the case. These dropdowns are automatically populated based on the input data that is saved in the model directory. Section 2.3 discusses how to use the Inputs Generator spreadsheet to view and create new input data.

Case common features define specific analytical features that are shared across all runs within the case. These include detailed T&D project deferral valuations, detailed energy EE measure calculations with dual baseline treatment, PV and storage sizing, and the option to use a faster optimization model that avoids running 8760-hour optimization for each year.

Common model configuration options generally do not need to be changed, but provide users with some control over how the optimization model runs. These customization options include the optimization length (i.e. the number of hours that are dispatched together) and output reporting settings.

Figure 2-5 Model Dashboard/0. Case Configuration: Setting up a Case

Case Control

Case Name
e3_single_year_tx_2

2. Save Case Settings

3. Select Cases to Run

Load Saved Case Settings

Refresh Dropdowns

Runs

Input	pv	pv+storage	
System Scenario Name	E3 Example System	E3 Example System	
Enable Ancillary Services	TRUE	TRUE	
Customer Name	large_user	large_user	
Enable Customer Load Modifier	TRUE	TRUE	
Rate Scenario	E19_scenario	E19_scenario	
Customer DGPV (fixed kW or % of Customer Lo	50%	50%	
Dispatchable Technology Installation Year	2018	2018	
Technology Control Arrangement	customer control	customer control	
Storage Technology	NA	li_ion_90kW_2hours	
Managed EV Technology	NA	NA	
Distributed CT Technology	NA	NA	
Smart HVAC Technology	NA	NA	
Smart Water Heater Technology	NA	NA	
Distribution Location Name	DPA2	DPA2	
Distribution Avoided Cost Level	default	default	
Programs: Custom Signal Name	cs_1	cs_1	
Programs: RA Program Name	ra_1	ra_1	
Financial Scenario	base	base	

Case Common Features

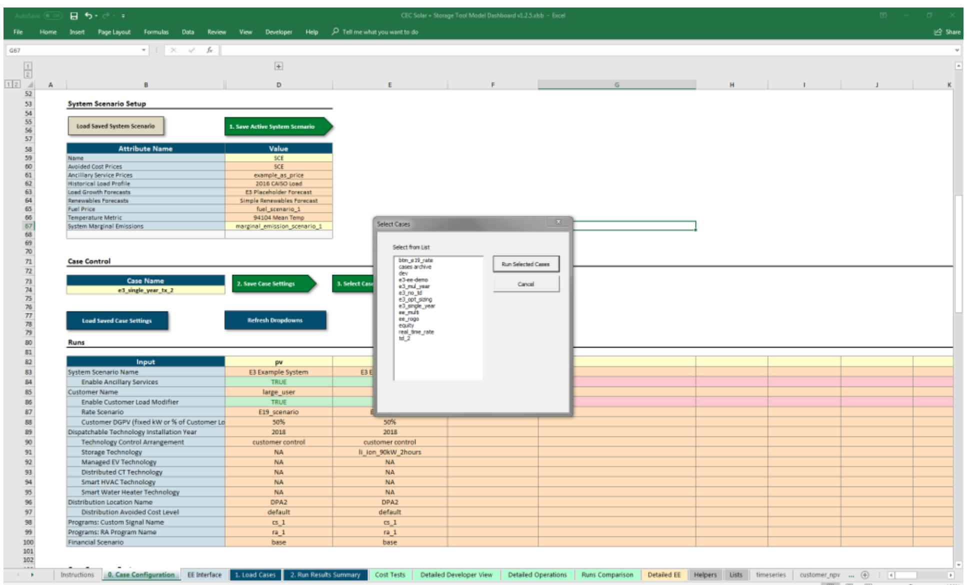
Feature	Value	Unit
Customer: Detailed Load Modifiers	TRUE	*Boolean*
Distribution: Detailed T&D Deferral	FALSE	*Boolean*
Distribution: Detailed Interconnection Costing	TRUE	*Boolean*
Opt: Run PV Sizing	FALSE	*Boolean*
Opt: Run Storage Sizing	FALSE	*Boolean*
Opt: Use Fast Optimization Model	FALSE	*Boolean*

Case Common Model Configuration

Attribute	Value	Unit
Opt: Optimization Length	8760	*Hours*
Programs: Contract Day Count	10	*Day*
Run: Only Run Installation Year	TRUE	*Boolean*
System: Scale Load to Energy	TRUE	*Boolean*
System: Scale Load to Peak	TRUE	*Boolean*
Opt: Available CPUs	all	/
Opt: Print Optimization Log	TRUE	*Boolean*
Opt: Run Permutations	FALSE	*Boolean*
Output: Annual Settings	aot_1	/
Output: Technology Loading Order	tlo_1	/
Output: Timeseries Settings	tot_1	/
Output: Include Timeseries Results	TRUE	*Boolean*
Input: Link Technology Parameters to Installed Yea	TRUE	*Boolean*

Once a case has been configured and saved using “2. Save Case Setting,” users can use the green “3. Select Cases to Run” button, which will invoke a pop-up window, as shown in the Figure 2-6. From this popup window, users can select one or multiple cases to send to the Python model. When the user presses “Run Selected Cases”, a command line window will open, showing the model’s progress. When the model is finished running, the user should close the command line window and proceed to viewing results.

Figure 2-6 Model Dashboard/0. Case Configuration: Selecting Cases to Run



To view the results of cases, users should proceed to the ***1. Load Cases*** tab on the Model Dashboard. Pressing the “Select Cases to Load into Results Viewer” button will invoke a similar popup window that allows users to select one or multiple cases to load into the dashboard. On subsequent tabs of the Model Dashboard, users can view detailed results for individual runs and compare runs across the cases that have been loaded into the dashboard. For more details, see Section 2.2.1.

2.1.1.2 Inputs Generator: Generating, Saving, and Loading Input Data

To represent the cost-effectiveness of DER projects, model takes in project information regarding the technology operating parameters and sizes, customer load and rates, and system avoided costs to calculate the DER impact to the electricity system.

Default inputs for California are saved in the data folders. The descriptions and sources for the default inputs can be find in the appendix. If users would like to add in new data or use customized data, please use the "Inputs Generator.xlsb" to enter and save inputs. has detailed descriptions on inputs and users can use that to create corresponding inputs. Chapter 2.3 describes the "Input Generator" interface in details.

2.1.2 SIMPLIFIED CASE SETUP – SOLAR + STORAGE USE CASES

This UI provides an easy setup for the users who are interested in targeting DER technologies for NWAs and distribution deferral values. For example, utility staffs who are preparing for DDOR filings can use this UI to calculate marginal distribution avoided costs for distribution locations that have deferral potential. And developers who are preparing for NWA RFP can also use this to screen for the valuable distribution locations and suitable technologies.

The instructions on setting up cases and results viewing are covered in Chapter 2.4.

2.1.3 SIMPLIFIED CASE SETUP – DISTRIBUTION VALUES SCREENING

This UI provides an easy setup for the users who are interested targeting DER technologies for non-wires alternatives (NWAs) and distribution deferral values. For example, utility staffs who are preparing for Distribution Deferral Opportunity Report (DDOR) filings can use this UI to calculate marginal distribution avoided costs for distribution locations that have deferral potential. And developers who are preparing for NWA Request for Proposal (RFP) can also use this to screen for the valuable distribution locations and suitable technologies.

Instructions on setting up cases and viewing results in this UI are in Chapter 2.5.

2.2 Model Dashboard

2.2.1 MODEL DASHBOARD WORKFLOW

The Model Dashboard spreadsheet is where users will spend most of their time interacting with the model, as it is the main interface for setting up new cases, running cases through the Python modules, and viewing results across cases.

The Model Dashboard workflow is comprised of five main steps:

+ Configure and run new cases
+ Load case results into the Model Dashboard
+ Select a single run to view detailed results
+ View cost test and operational results for a selected run and compare results across multiple runs
+ If optional features such as **Detailed T&D Deferral** and **Detailed Load Modifiers** are enabled, additional results are presented in the dashboard interface

2.2.1.1 Case Configuration

A **Case** is defined in the tool as a set of individual runs and common case features and model options.

System Scenarios

System scenarios define the combination of system-level data, such as avoided costs, ancillary service prices, and system load and renewables. Users must define the individual timeseries for each datatype (each of which will be described in subsequent sections of this User Guide), as well as the combination of data that comprises the system scenario, as in Figure 2-7.

Figure 2-7 Model Dashboard/0. Case Configuration: Example System Scenario Configuration

Attribute Name	Value
Name	SCE
Avoided Cost Prices	SCE
Ancillary Service Prices	historic_escalated
Historical Load Profile	2016 CAISO Load
Load Growth Forecasts	E3 Placeholder Forecast
Renewables Forecasts	Simple Renewables Forecast
Fuel Price	socal_citygate
Temperature Metric	94104 Mean Temp
System Marginal Emissions	SCE
Load modifier load shapes	California

Runs

Individual runs define the combination of system scenario, customer, and technology data for each optimization run in the Python code. All 19 rows of each run must be filled, including the run's name (e.g., "pv" and "pv+storage" in Figure 2-8), for each run to be valid.

Figure 2-8 Model Dashboard/0. Case Configuration: Example Run Configuration

Input	pv	pv+storage
System Scenario Name	E3 Example System	E3 Example System
Enable Ancillary Services	TRUE	TRUE
Customer Name	large_user	large_user
Enable Customer Load Modifier	TRUE	TRUE
Rate Scenario	E19_scenario	E19_scenario
Customer DGPV	50%	50%
Dispatchable Technology Installation Year	2018	2018
Technology Control Arrangement	customer control	customer control
Storage Technology	NA	li_ion_90kW_2hours
Managed EV Technology	NA	NA

Distributed CT Technology	NA	NA
Smart HVAC Technology	NA	NA
Smart Water Heater Technology	NA	NA
Distribution Location Name	DPA2	DPA2
Distribution Avoided Cost Level	default	default
Programs: Custom Signal Name	cs_1	cs_1
Programs: RA Program Name	ra_1	ra_1
Financial Scenario	base	base

Features

Available features are shown in Figure 2-9 below. These features can be enabled when users are interested in analyzing the optimal sizes for PV and storage as well as detailed calculations for some technology, value streams, potential costs, and financing costs. The descriptions for all features are listed below.

+ **Case Name:** Identifier for the case.
+ **Detailed Load Modifiers:** Enable multiple, individual static load modifiers to be analyzed through the Solar + Storage Tool using a dual baseline treatment to attribute benefits to new or retrofit measures.
+ **Detailed T&D Deferral:** Enable project-specific distribution deferral values defined in Distribution Locations instead of the system-average Distribution Avoided Costs. Enabling this feature will substitute the system-level avoided costs with the project-specific values instead of having the two be additive.
+ **Detailed Interconnection Costing:** Calculate whether customer energy exports to the grid are large enough to trigger an interconnection cost that the customer must pay.
+ **PV Sizing:** Instead of using the PV size defined as a percentage of customer load or fixed value in the **Run**, calculate the optimal size of a PV system for the customer by maximizing the net present value of the net benefits for the specified DER project.

- **Storage Sizing:** Instead of using the storage size defined by the storage technology active in the **Run**, calculate the optimal size of a storage system for the customer by maximizing the net present value of the net benefits for the specified DER project.
- **Use Fast Optimization Model:** Instead of running each day of the year to determine optimal technology dispatch, run a heuristic dispatch based on a sample of representative days (more details Section 3.4.3.7).
- **Allow PV Curtailment:** Allow PV generation to be economically curtailed (e.g., used in conjunction with the Detailed Interconnection Costing functionality).
- **Calculate Pro Forma:** Determine whether to use the build-in pro forma for project financing costs calculation.

Figure 2-9 Model Dashboard/0. Case Configuration: Example Case Features

Feature	Value
Customer: Detailed Load Modifiers	TRUE
Distribution: Detailed T&D Deferral	FALSE
Distribution: Detailed Interconnection Costing	FALSE
Opt: Run PV Sizing	FALSE
Opt: Run Storage Sizing	FALSE
Opt: Use Fast Optimization Model	FALSE
Opt: Allow PV Curtailment	FALSE
Calculate Pro Forma	TRUE

Model Configurations

- Several model options give the user some control over how the Python code interprets input data and runs the optimization, shown in **System: Scale Load to Energy:** If enabled, the historical system load shape will be scaled based on the total annual energy (GWh) for each optimization year.
- **System: Scale Load to Peak:** If enabled, the historical system load shape will be scaled based on the annual peak power (MW) for each optimization year.

- **Run: Project Lifetime:** The lifetime of the specified DER project. Financing costs, debt period, and technology replacement are based on the project lifetime.
- **Run: Pro Forma Auto Replacement:** Determines if technologies are replaced automatically when reaching their own lifetime before the project lifetime.
- **Run: Only Run Installation Year:** If enabled, the model will only run the installation year defined for the run. All subsequent year benefit calculations will just be escalated from the first year's calculations.
- **Run: Enable Remapping**: If enabled, timeseries data from different years will be remapped using a common temperature metric so that similar days are matched to each other.
- **Programs: Contract Day Count:** If the user selects the **utility control (contract days)** for the Technology Control Arrangement, the number of contract days defined in this field will be selected – based on a PCAF method – as the days in which the dispatchable technologies will be dispatched for system benefit instead of customer benefit.
- **Output: Cost Tests Scenario:** The scenario used for defining cost test components.
- **Opt: Run Permutations:** Run permutations of all customers/technologies defined in the Runs definition table. For example, if two runs are defined in the Runs table with two different customers and two different sets of dispatchable technologies, four runs will be returned by the model. Default is set to False.
- **Opt: Print Optimization Log:** Print optimization solver diagnostic log (for diagnostics).
- **Opt: Optimization Length:** By default, the optimization window will split each dispatch year into 7-day segments. Optionally, users can select longer or shorter optimization windows; however, changing this configuration parameter is generally not needed. If PV or Storage Sizing is selected, the Optimization Length should automatically adjust to the required 8760 hours for those features.
- **Opt: Available CPUs:** Number of CPU cores available to the model for optimization.
- **Input: Link Technology Parameters to Installed Years:** When enabled, technology annual parameters will be fixed based on the installation year vintage. If disabled, the model will

read the annual parameter values for each new year that is run. Disabling this may be used if the user wants to have certain parameters (e.g., battery roundtrip efficiency) to vary by year.

Figure 2-10. We have hidden some system settings that we don't expect users to interact with in grey.

- **System: Scale Load to Energy:** If enabled, the historical system load shape will be scaled based on the total annual energy (GWh) for each optimization year.
- **System: Scale Load to Peak:** If enabled, the historical system load shape will be scaled based on the annual peak power (MW) for each optimization year.
- **Run: Project Lifetime:** The lifetime of the specified DER project. Financing costs, debt period, and technology replacement are based on the project lifetime.
- **Run: Pro Forma Auto Replacement:** Determines if technologies are replaced automatically when reaching their own lifetime before the project lifetime.
- **Run: Only Run Installation Year:** If enabled, the model will only run the installation year defined for the run. All subsequent year benefit calculations will just be escalated from the first year's calculations.
- **Run: Enable Remapping**: If enabled, timeseries data from different years will be remapped using a common temperature metric so that similar days are matched to each other.
- **Programs: Contract Day Count:** If the user selects the **utility control (contract days)** for the Technology Control Arrangement, the number of contract days defined in this field will be selected – based on a PCAF method – as the days in which the dispatchable technologies will be dispatched for system benefit instead of customer benefit.
- **Output: Cost Tests Scenario:** The scenario used for defining cost test components.
- **Opt: Run Permutations:** Run permutations of all customers/technologies defined in the Runs definition table. For example, if two runs are defined in the Runs table with two

different customers and two different sets of dispatchable technologies, four runs will be returned by the model. Default is set to False.

- **Opt: Print Optimization Log:** Print optimization solver diagnostic log (for diagnostics).
- **Opt: Optimization Length:** By default, the optimization window will split each dispatch year into 7-day segments. Optionally, users can select longer or shorter optimization windows; however, changing this configuration parameter is generally not needed. If PV or Storage Sizing is selected, the Optimization Length should automatically adjust to the required 8760 hours for those features.
- **Opt: Available CPUs:** Number of CPU cores available to the model for optimization.
- **Input: Link Technology Parameters to Installed Years:** When enabled, technology annual parameters will be fixed based on the installation year vintage. If disabled, the model will read the annual parameter values for each new year that is run. Disabling this may be used if the user wants to have certain parameters (e.g., battery roundtrip efficiency) to vary by year.

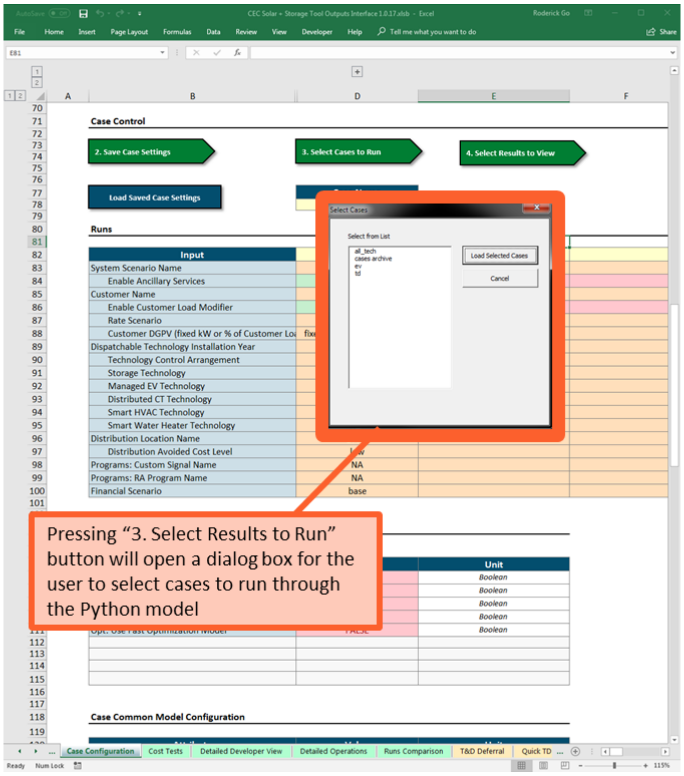
Figure 2-10 Model Dashboard/0. Case Configuration: Example Case Model Configuration

Attribute	Value	Unit
System: Scale Load to Peak	TRUE	*Boolean*
System: Scale Load to Energy	TRUE	*Boolean*
Run: Project Lifetime	max_lifetime	
Run: Pro Forma Auto Replacement	TRUE	*Boolean*
Run: Only Run Installation Year	TRUE	*Boolean*
Run: Enable Remapping	FALSE	*Boolean*
Programs: Contract Day Count	10	*Day*
Output: Cost Tests Scenario	cost_tests	
Opt: Run Permutations	FALSE	*Boolean*
Opt: Print Optimization Log	FALSE	*Boolean*
Opt: Optimization Length	24	*Hour*
Opt: Available CPUs	all	
Input: Link Technology Parameters to Installed Years	TRUE	*Boolean*

Running the Defined Case

Once a case has been configured and saved using “2. Save Case Setting,” users can use the green “3. Select Cases to Run” button, which will invoke a pop-up window, as shown in the chart below. From this popup window, users can select one or multiple cases to send to the Python model. When the user presses “Run Selected Cases,” a command line window will open, showing the model’s progress. When the model is finished running, the user should close the command line window and proceed to viewing results.

Figure 2-11 Model Dashboard/0. Case Configuration: Running the Defined Case

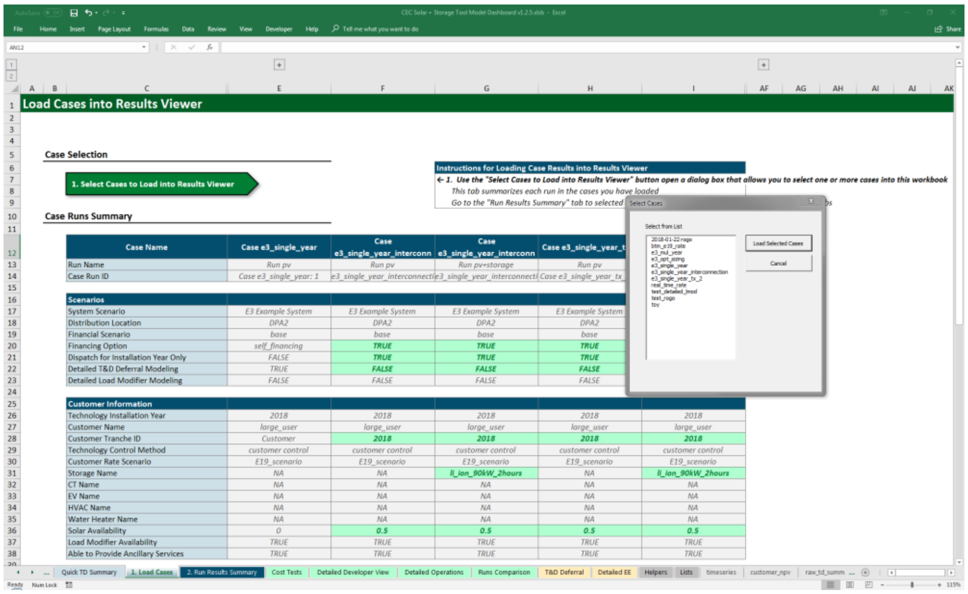


2.2.1.2 Load Cases

The ***1. Load Cases*** tab is the second step in the Model Dashboard workflow, allowing users to view what cases are in the model directory and choose multiple cases to load into the spreadsheet to view. As with the Case Configuration tab, pressing the "Select Cases to Load into Results Viewer" button will engage a popup window in which users can select multiple available cases. Pressing "Load Selected Cases" will invoke VBA code to copy the results into the spreadsheet.

Once the cases have been loaded into the spreadsheet, the Load Cases tab displays each run in the loaded cases and highlights differences between each run in green, as shown in Figure 2-12

Figure 2-12 Model Dashboard/1. Load Cases: Example of Load Cases Tab



2.2.2 ENERGY EFFICIENCY INTERFACE

The ***EE Interface*** tab provide a quick access to run the tool for the users who are only interested in energy efficiency measures. Users set up the analysis by filling in the energy efficiency measures in the table along with their expected electricity load reduction, expected fuel consumption reduction (if applicable), replacement method, remaining useful life, costs, and the corresponding customer information (customer type, rates, and distribution locations). Each row in the table contains the information for one energy efficiency measures the user wants to analyze. After the table is filled, the user can click "1. Save Detailed EE-only Case" and "2. Run Current EE-Only Case" to save and run the model. And after the model is finished running, user can load in and view the results through the ***1. Load Cases*** tab. Instructions for loading in results are included in the next section.

Figure 2-13 Model Dashboard/EE Interface: Overview

Energy Efficiency Measures

1. Save Detailed EE-Only Case

2. Run Current EE-Only Case

Load Previous EE-Only Case

Instructions

Case Name	Utility Name
e3-ee-demo	SDG&E

Case Features and Configurations

Feature	Value	Unit
Distribution: Detailed T&D Deferral	FALSE	*Boolean*
Distribution: Detailed Interconnection Costing	FALSE	*Boolean*
Opt: Allow PV to Be Curtailable	FALSE	*Boolean*
Run: Only Run Installation Year	TRUE	*Boolean*

Energy Efficiency Measures

Load Modifier Name	Electricity Load Reduction Impact Shape	Building Fuel Type	Fuel Consumption Reduction Impact Shape	Annual Fuel Consumption Reduction from EE	Replacement Method
				MMBtu/measure/yr	
lmod_id	*nod_electricity_shape_nam*	*fuel_type*	*d_fuel_impact_shape_na*	*lmod_annual_fuel_reduction*	*replacement_method*
Comm Lighting 1	GE-Non_Res:Indoor_CFL_L	gas	Flat_Impact	1	Retrofit
Comm Lighting 2	Non_Res:Indoor_Non-CF	gas	Flat_Impact	1	New
Comm HVAC 1	GE-Non_Res:HVAC_Chille	gas	Flat_Impact	1	New
Ind HVAC 1	GE-Non_Res:HVAC_Chille	gas	Flat_Impact	1	New
Res Lighting 1	PGE-Res:Indoor_CFL_Ltg	gas	Flat_Impact	1	Retrofit
Res Refrig 1	PGE-Res:RefgFrzr_HighEff	gas	Flat_Impact	1	Retrofit
Res HVAC 1	PGE-Res:HVAC_Eff_AC	gas	Flat_Impact	1	ROB
Res Dishwasher 1	GE-Res:ClothesDishWash	gas	Flat_Impact	1	ROB
Res Insulation 1	PGE-Res:BldgShell_Ins	gas	Flat_Impact	1	ROB
Res HVAC 2	PGE-Res:HVAC_Eff_HP	gas	Flat_Impact	1	ROB

2.2.3 GENERAL RESULTS TABS

2.2.3.1 Run Results Summary

The ***2. Run Results Summary*** tab gives an overview of the run, showing key input parameters and features for the run as well as the B/C ratios for each type of technology enabled in the run. More detailed results are shown on the subsequent tabs of the Model Dashboard.

To select a run to view, users can select from the available runs in the dropdown at the top left corner of the sheet, in the table labeled "2. Select Run to View," as shown in the Figure 2-14. The available runs correspond to the runs displayed on the ***1. Load Cases*** tab. Once a value has been selected from the dropdown, the workbook should automatically recalculate, displaying the relevant run results.

Going further down the sheet, the table labeled "3. Select T&D Deferral Methodology to Use" will be greyed out and inactive if the Detailed T&D Project Deferral feature was not enabled for the current case being viewed. However, if that feature is enabled, the user can select to show results using different deferral and peak reduction calculation methods.

Finally, the "4. Select Units to Use" table allows users to change the units used to display benefits and costs. By default, values will be displayed in $ for the installation year of the run. However, users can select to levelize those costs relative to the kW installed of one of the technologies (e.g. the user could levelize benefits/costs over the kW installed DGPV).

Figure 2-14 Model Dashboard/2. Run Results Summary: Example Run Selection

Run Selection

2. Select Run to View	
Case and Run Name to View	**Case e3_single_year_tx_2: Run pv**
	Case e3_single_year_tx_2: Run pv
	Case e3_single_year_tx_2: Run pv+storage

3. Select T&D Deferral Methodology to Use	
Deferral Method	*Allocation-based Average*
Peak Reduction Method	*PCAF*

4. Select Units to Use	
Units	**(2018 $)**

In the middle of the sheet, users will find summarized benefits and costs for each technology category in the run. B/C ratios greater than 1.0 will be highlighted in green, as shown in Figure 2-15.

Figure 2-15 Model Dashboard/2. Run Results Summary: Example Run Benefits and Costs by Technology Category

Current Run B/C Ratios

Technology	TRC	RIM	PCT	SCT	Customized
Load Modifier	89.40	0.75	115.43	96.22	100.49
PV	4.49	0.58	7.48	4.56	5.24
Storage	-	-	-	-	-
CT	-	-	-	-	-
EV Managed Charging	-	-	-	-	-
HVAC	-	-	-	-	-
Water Heater	-	-	-	-	-
Total	**4.63**	**0.60**	**7.46**	**4.73**	**5.38**

Current Run Benefits (2018 $)

Technology	TRC	RIM	PCT	SCT	Customized
Load Modifier	$ 49,546	$ 49,546	$ 63,108	$ 55,016	$ 54,938
PV	$ 376,361	$ 355,333	$ 600,338	$ 419,331	$ 420,539
Storage	$ -	$ -	$ -	$ -	$ -
CT	$ -	$ -	$ -	$ -	$ -
EV Managed Charging	$ -	$ -	$ -	$ -	$ -
HVAC	$ -	$ -	$ -	$ -	$ -
Water Heater	$ -	$ -	$ -	$ -	$ -
Total	**$ 434,938**	**$ 413,910**	**$ 673,266**	**$ 484,857**	**$ 485,124**

Current Run Costs (2018 $)

Technology	TRC	RIM	PCT	SCT	Customized
Load Modifier	$ 554	$ 66,364	$ 547	$ 572	$ 547
PV	$ 83,905	$ 611,520	$ 80,304	$ 92,042	$ 80,304
Storage	$ -	$ -	$ -	$ -	$ -
CT	$ -	$ -	$ -	$ -	$ -
EV Managed Charging	$ -	$ -	$ -	$ -	$ -
HVAC	$ -	$ -	$ -	$ -	$ -
Water Heater	$ -	$ -	$ -	$ -	$ -
Total	**$ 93,992**	**$ 688,452**	**$ 90,209**	**$ 102,517**	**$ 90,209**

In addition to high-level results, the Run Results Summary tab shows the definition of the various cost tests used throughout the workbook. The cost test definition sets are set up in “Inputs Generator” UI and assigned to each case in the configuration section in the case configuration process. More details on cost tests including which benefits and costs are included in each cost test are described in Chapter 3.3.

- Total Resource Cost (TRC)
- Ratepayer Impact Measure (RIM)
- Participant Cost Test (PCT)
- Societal Cost Test (SCT)
- Program Administrative Cost (PAC) Test
- Pro Forma: is used for determining the value streams that are included in the financing calculation

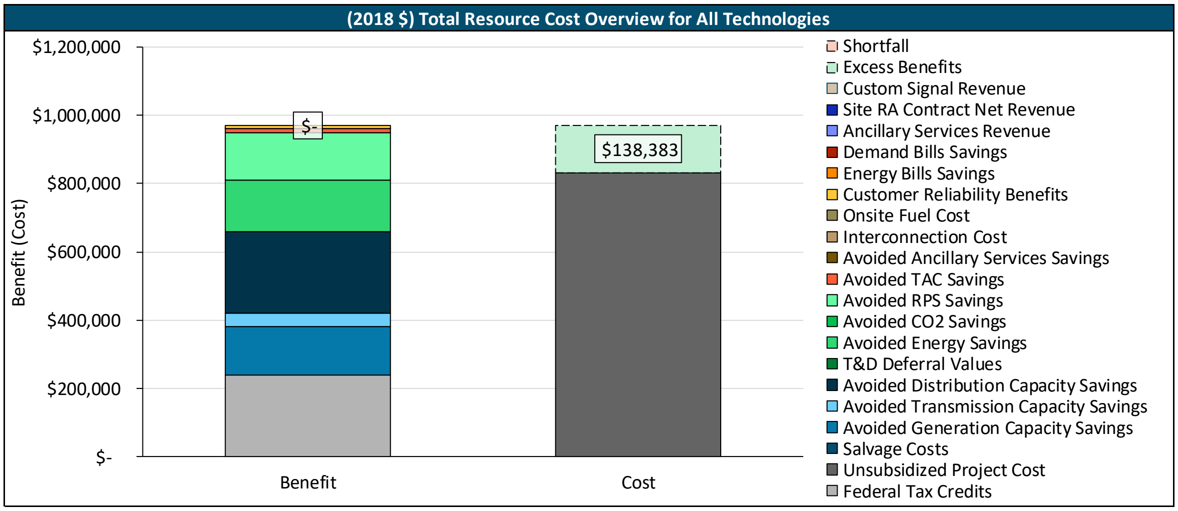
Figure 2-16 Model Dashboard/2. Run Results Summary: Cost Test Definitions

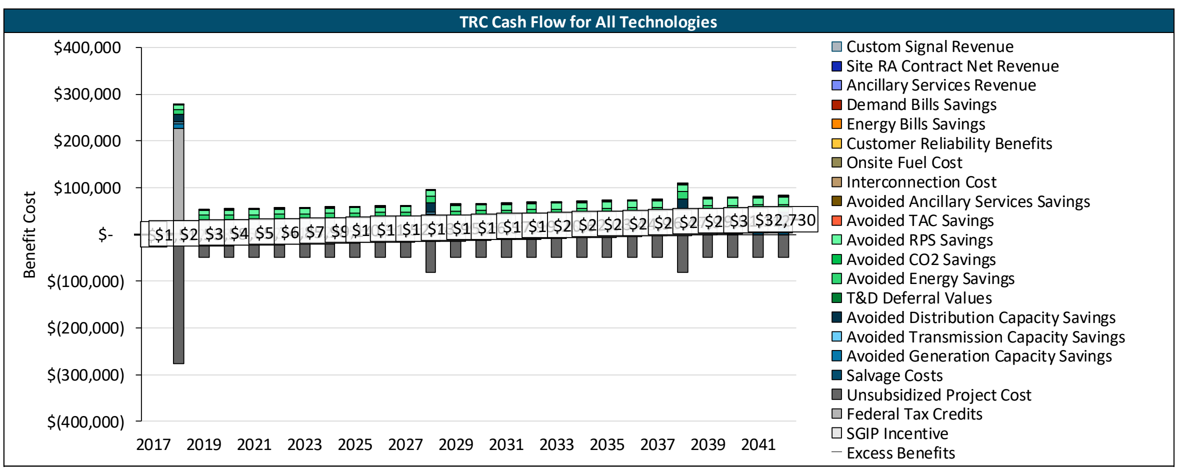
Value Components	TRC	RIM	PCT	SCT	PAC	Pro Forma
Applicable Discount Rate	*Utility*	*Utility*	*Customer*	*Societal*	*Utility*	*Customer*
Avoided Energy	100%	100%	0%	100%	100%	0%
Avoided Generation Capacity	100%	100%	0%	100%	100%	0%
Avoided Transmission Capacity	100%	100%	0%	100%	100%	0%
Avoided Distribution Capacity	100%	100%	0%	100%	100%	0%
T&D Deferral Value	100%	100%	0%	100%	100%	0%
Avoided Ancillary Services	100%	100%	0%	100%	100%	0%
Avoided Monetized Carbon (cap and trad	100%	100%	0%	100%	100%	0%
Avoided GHG adder	100%	100%	0%	100%	100%	0%
Avoided Losses	100%	100%	0%	100%	100%	0%
Customer Energy Charge Savings	0%	-100%	100%	0%	0%	100%
	0%	-100%	100%	0%	0%	100%
	0%	-100%	100%	0%	0%	100%
Monthly Demand Charge Savings	0%	-100%	100%	0%	0%	100%
Daily Demand Charge Savings	0%	-100%	100%	0%	0%	100%
Contract Demand Charge Savings	0%	-100%	100%	0%	0%	100%
Total RA Program Admin Cost	-100%	-100%	0%	-100%	-100%	0%
Total RA Customer Inconvenience Cost	-100%	0%	-100%	-100%	-100%	0%
Total RA Net Profit	0%	-100%	100%	0%	0%	100%
Custom Signal Revenue	0%	-100%	100%	0%	0%	100%
Customer Reliability Benefits	100%	100%	0%	100%	100%	0%
Avoided ICE Savings from EV	100%	0%	100%	100%	100%	100%
Non-Spinning Reserve Revenue	0%	0%	0%	0%	100%	0%
Regulation Down Reserve Revenue	0%	0%	0%	0%	100%	0%
Regulation Up Reserve Revenue	0%	0%	0%	0%	100%	0%
Spinning Reserve Revenue	0%	0%	0%	0%	100%	0%
State Incentive	0%	-100%	100%	0%	0%	100%
Federal Tax Credits	100%	0%	100%	100%	100%	100%
Unsubsidized Project Cost	-100%	0%	-100%	-100%	-100%	0%
Project Cost	0%	0%	0%	0%	-100%	0%
Salvage Value	0%	0%	0%	0%	100%	100%
Net Financing Cost	0%	0%	0%	0%	-100%	-100%
Operating Cost	0%	0%	0%	0%	-100%	-100%
Equity Investment Cost	0%	0%	0%	0%	-100%	-100%
Tax Payment Savings	0%	0%	0%	0%	100%	100%
Utility Incentive Payment	0%	-100%	100%	0%	-100%	100%

2.2.3.2 Cost Tests

Cost test results are presented in both NPV and nominal cash flow forms, as shown below.

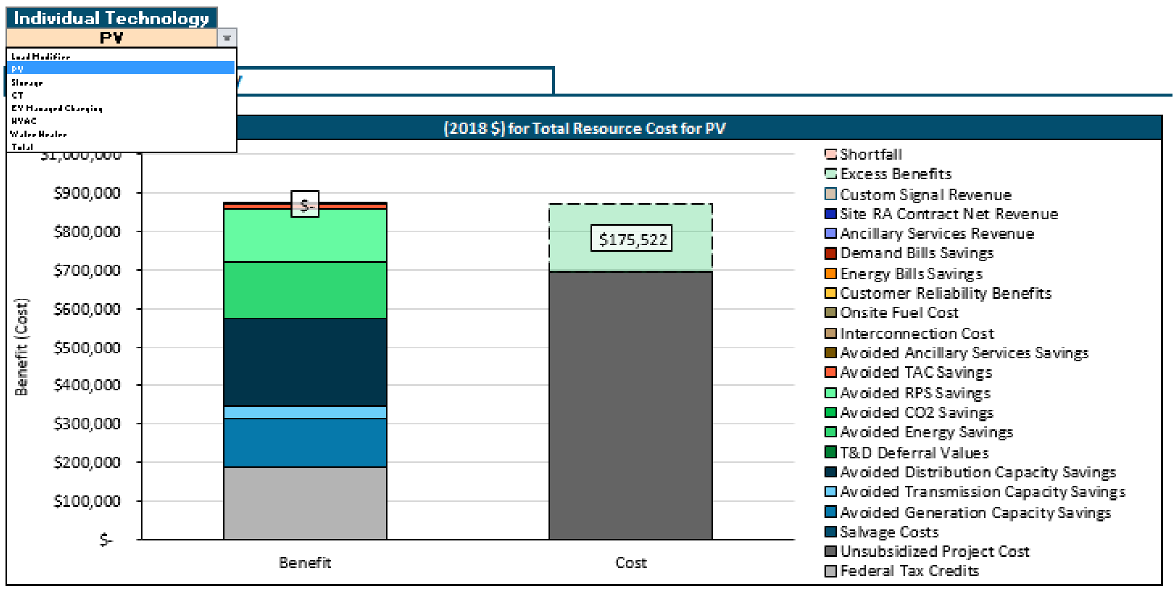
Figure 2-17 Model Dashboard/Cost Tests: Example NPV Plot for the Total Resource Cost Test for the DER portfolio





Results are presented in both as the whole project (e.g. PV + Storage) on the left-hand-side of the tab and as individual technologies on the right-hand-side of the tab. By selecting the technology from the dropdown on the right side of the tab, users can investigate the cost-effectiveness of each technology individually.

Figure 2-18 Model Dashboard/Cost Tests: Example NPV Plot for the Total Resource Cost Test for An Individual Technology



2.2.3.3 Detailed Developer View

The Detailed Developer View tab expands on the other cost test results by breaking out solar + storage project costs into separate components for:

- Operating cost
- Net finance cost (debt payment costs)
- Equity investment cost
- Tax payment savings (tax refunds)

Similar to the results in the **Cost Tests** tab, costs and benefits are also shown in both NPV and annual cash flow. This tab is intended for developers who finance their project through the combination of debt and equity to show a breakdown of the costs and cashflow over project's lifetime. If the project is purchased through a third party PPA or a lease agreement, the project costs won't be broken out by components.

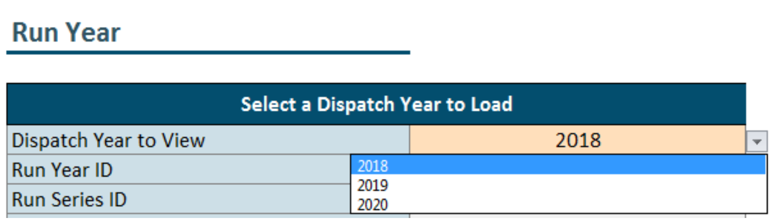
the Unlike the ***Cost Tests*** tab, the results shown on this tab are only intended for PV and storage technologies.

2.2.3.4 Detailed Operations

The Solar + Storage Tool is designed to run an annual dispatch optimization for all specified technology and for each customer. The results interface compiles the dispatch results from the optimization and displays the component contributions of the various dispatchable technologies to the customer's load.

To view a detailed annual dispatch, the user selects an available dispatch year for the current run from the dropdown menu in the top left corner of the tab, as shown below.

Figure 2-19 Model Dashboard/Detailed Operations: Example Dropdown Menu for Run Detailed Operations Selection



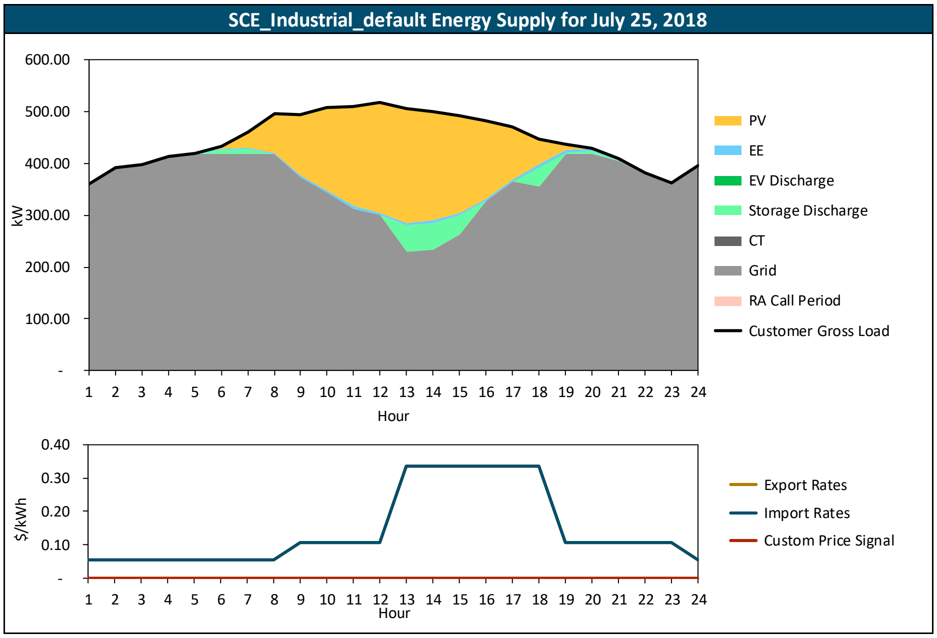
Once the user presses the "Load Timeseries Results" button, the tool will load in the hourly timeseries data and update the dispatch charts in the tab.

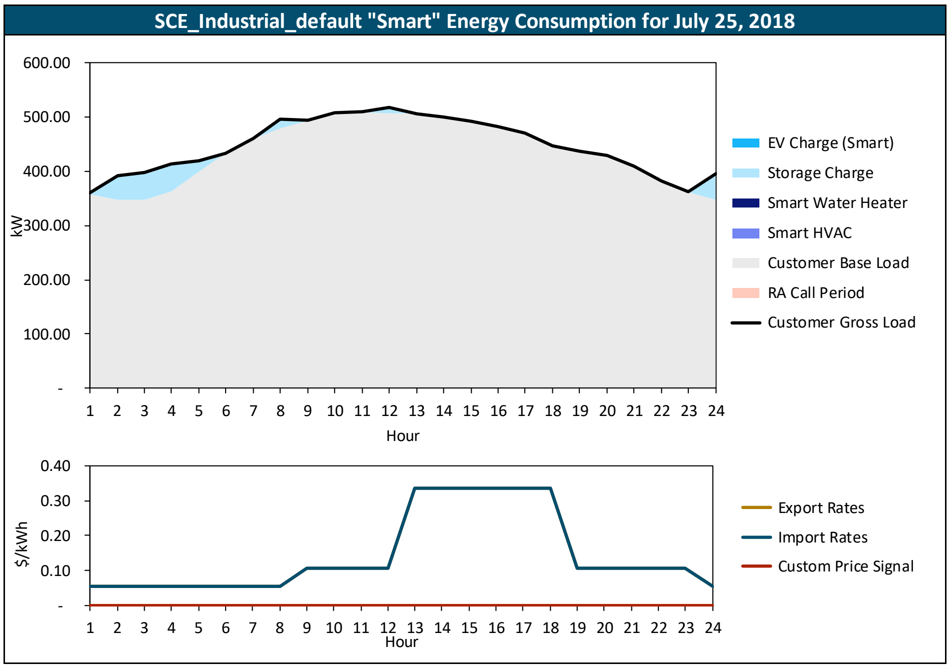
This tab has charts in the following three categories to provide a detailed view into dispatch pattern for different technology:

Onsite Energy Overview

This category gives the overview of the project onsite energy supply and consumptions broken down by technology and grid import as shown in the figure below. These charts can show how onsite load changes after adding in the DER system and how different technologies interact with each other to reduce demand charges.

Figure 2-20 Model Dashboard/Detailed Operations: Example Plot for Energy Supply and Energy Consumption Overview

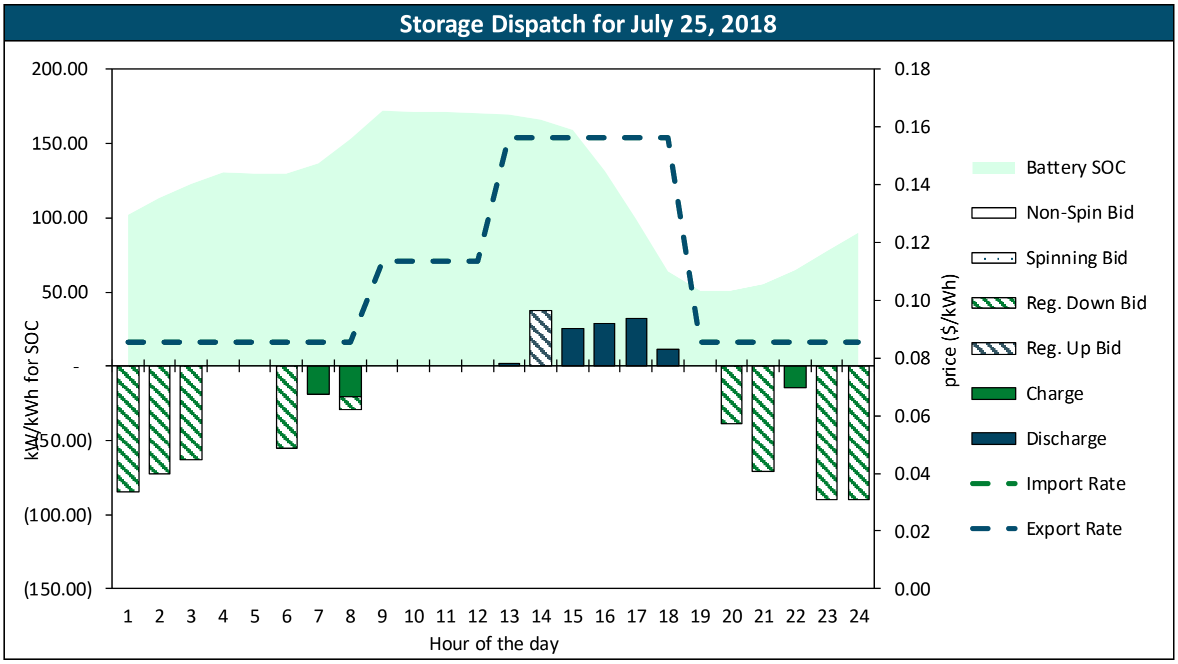




Technology Dispatch

This section provides the detailed dispatch operation for each technology, including storage, fuel cell generator (CT), electric vehicle managed charging, smart water heater, and smart HVAC. The following figure shows an example storage dispatch. Operation are broken down by services the technology provides.

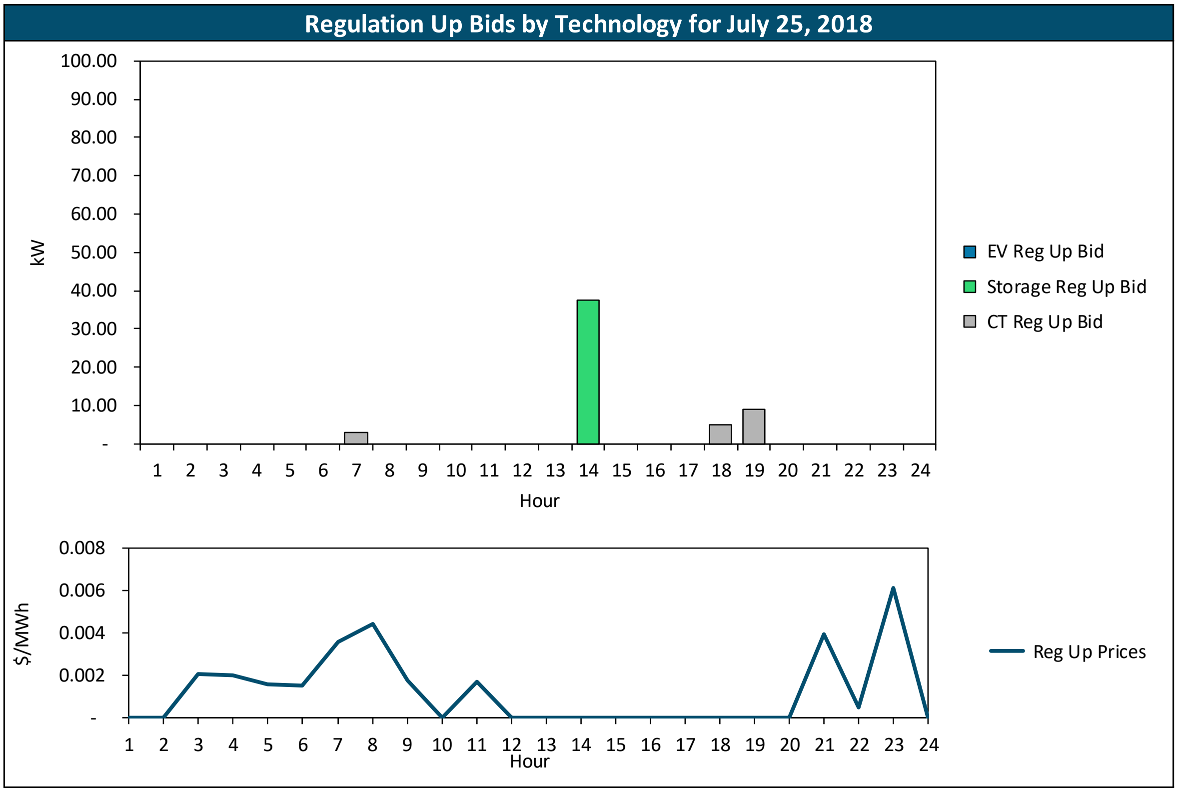
Figure 2-21 Model Dashboard/Detailed Operations: Sample Storage Dispatch



Ancillary Services

This section appears when ancillary service provision is enabled and shows how much ancillary services are provided by different technologies. The following chart shows the technology regulation up services provision. There are also similar charts for other ancillary services.

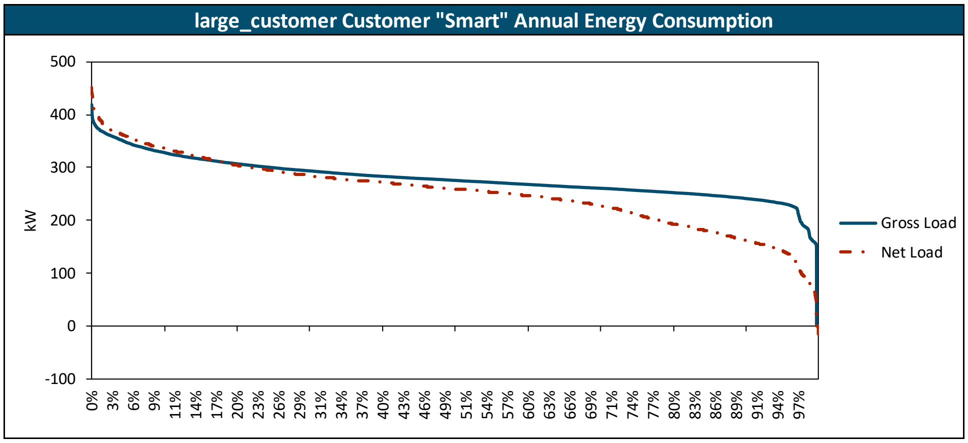
Figure 2-22 Model Dashboard/Detailed Operations: Regulation Up Bids for Sample Storage Dispatch



Annual Summary (Load Duration Curve)

An annual duration curves comparing customer gross and net load after DERs is also shown, as in the example below:

Figure 2-23 Model Dashboard/Detailed Operations: Example Duration Curve of Gross and Net Load



2.2.3.5 Runs Comparison

On the ***Runs Comparison*** tab, users can compare overview results for different runs in the cases that were loaded into the tool on the ***1. Load Cases*** tab.

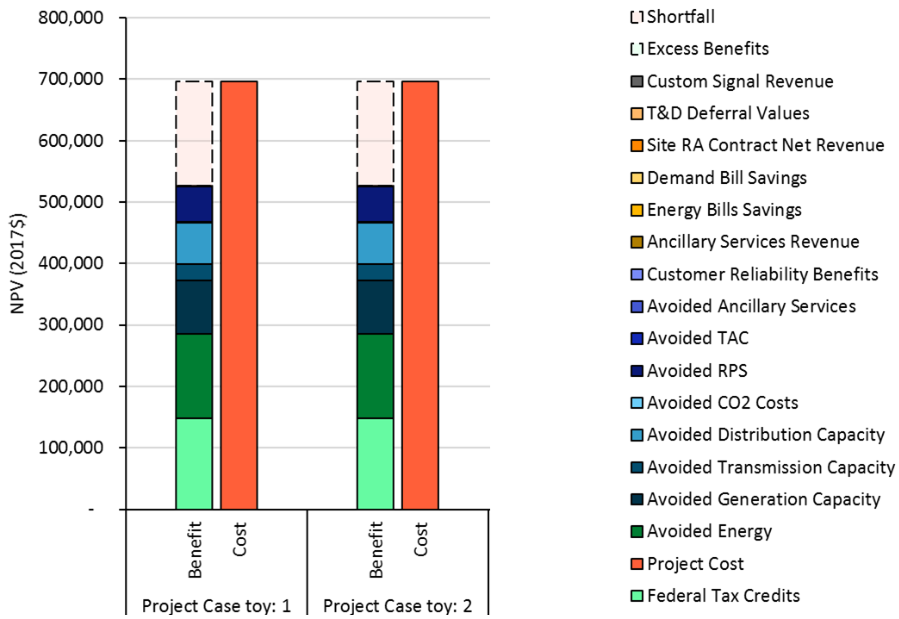
Figure 2-24 Model Dashboard/Runs Comparison: Example Runs Comparison Selection

	Cases to Compare	
Case and Run Name to View	Case e3_single_year_tx_2: Run pv	Case e3_single_year_tx_2: n pv+storage
Deferral Method	Threshold	Allocation-based Average
Peak Reduction Method	PCAF	PCAF

Case e3_single_year_tx_2: Run pv
Case e3_single_year_tx_2: Run pv+stor

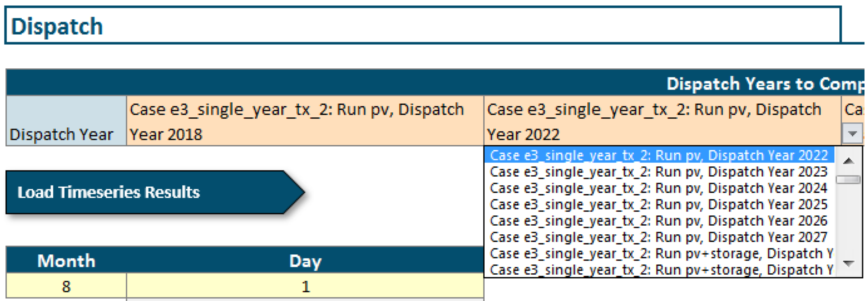
At the top right of the ***Runs Comparison*** tab, users will find several columns of orange dropdowns to select different runs. This is a condensed version of the dropdowns that users would find on the ***1. Load Cases*** tab. Once the spreadsheet has calculated, users can compare the cost test results for various runs, as shown in Figure 2-25.

Figure 2-25 Model Dashboard/Runs Comparison: Example Cost Test Comparison



Additionally, users can compare customer energy supply/demand across runs on the **Runs Comparison** tab. For dispatch comparisons, the user can select up to four different years to compare simultaneously, using the orange dropdown menus, as on the **Detailed Operations** tab. Once the user has pressed the "Load Timeseries Results" button, multiple years of dispatch data will be loaded into the tool, and the user can use the Month/Day selector to choose individual dispatch days to compare, as shown in Figure 2-26.

Figure 2-26 Model Dashboard/Runs Comparison: Day Dispatch Comparison Controls



2.2.4 FEATURE-SPECIFIC RESULTS TABS

This section describes result tabs shown for optional features including detailed T&D analysis and detailed energy efficiency analysis. T&D Deferral and Detailed EE tabs appear when the user selects the features when setting up the case. Those two tabs provide an in-depth look into the deferral values provided by specified DER project and energy efficiency results by measures.

2.2.4.1 T&D Deferral

This tab appears when detailed T&D deferral function is enabled for the case and provides details on T&D deferral results. Users can choose the methods for calculating peak load reduction contribution and deferral values in the **2. Run Results Summary** tab. The following tables and charts are shown in the tab:

- **Summary - Distribution deferral values summary table**: The summary of distribution deferral values for DERs that are installed in one distribution location – values are summarized for each upstream distribution location and are listed by technology.
- **Summary - Distribution deferral values summary chart:** The visualization in a chart for the aforementioned table.
- **Detailed Project Look - Peak Load and upgrade year before and after DER:** Peak Load and the upgrade timing before and after DER for a specific upgrade project.

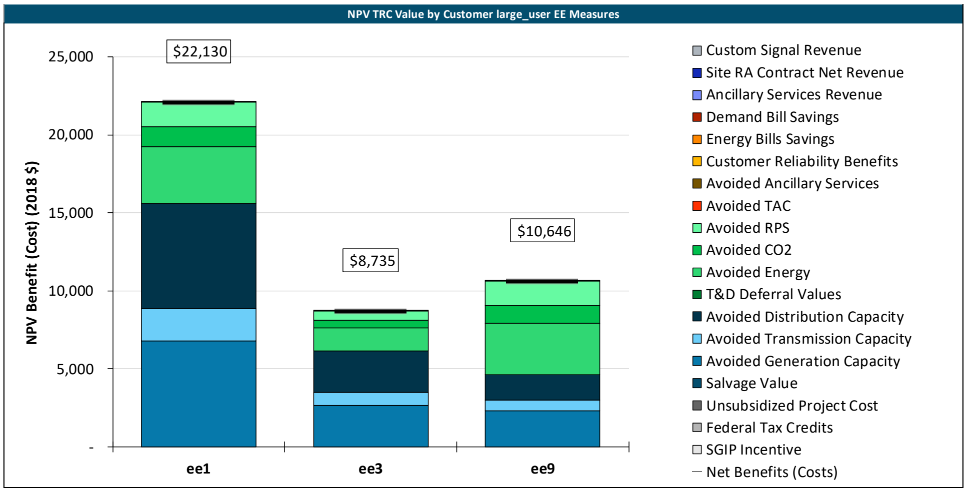
+ **Detailed Project Look – Peak Load Reduction by Technology:** Peak Load reduction by each DER technology for a specific upgrade project.
+ **Detailed Project Look – Peak Day Load Shape:** Load and DER shapes for the Peak Day.
+ **Detailed T&D Runs Comparison:** Here, the user can select different runs to compare the total deferral values side by side.

2.2.4.2 Detailed EE

Similar to the Cost Tests tab, the Detailed EE tab calculates the various cost test results; however, the cost tests are broken out for each individual detailed EE measure rather than the aggregate impact over all EE measures for the selected run.

With the Detailed Load Modifier feature enabled, the Solar + Storage Tool will calculate the annual benefits of each EE measure using the dual baseline treatment. The dual baseline treatment compares the savings associated with each measure to both code-standard and existing measures, depending on whether the measure is considered a retrofit measure or new/replace-on-burnout.

Figure 2-27 Model Dashboard/Detailed EE: Example Chart for NPV Benefits Summary



2.3 Inputs Generator

2.3.1 OVERVIEW

The Inputs Generator spreadsheet is a helper workbook that is meant to assist users in creating input .csv files in the correct format to be read in by the Python modules. The Inputs Generator also allows users to inspect existing input .csv files by loading them into a friendlier Excel interface, rather than opening raw .csv files within the model directory structure. The model comes with pre-loaded data for California IOUs, users would only need to use the Input Generator if users want to create specific project inputs.

Input data for the tool fall into seven categories:

- System Scenario
- Distribution System
- Rates
- Financials
- Cost Test Definitions
- Customers
- Technologies
- Utility Programs

Each of these categories of data will be described in this user guide.

On data input each sheet, the user will find a similar interface, with tables of inputs presented as well as the options to save data, load data, and refresh a list. For example, the **System Load** tab provides the following interface.

Figure 2-28 Inputs Generator/System Load: An example for the common data sheet structure

Load Growth Forecast Name

Save Active Load Growth Forecast

Load Growth Forecast Name
E3 Placeholder Forecast

Refresh Saved Load Growth Forecasts

Load Saved Load Growth Forecast

Saved Load Growth Forecasts
E3 Placeholder Forecast

Load Growth Forecast

Weather Year	Net Energy for Load (GWh)	1-in-2 Peak (MW)
2016	228794	46232
2017	228191	50116
2018	228191	46625
2019	228191	46625
2020	228191	46625
2021	228191	46625
2022	228191	46625
2023	228191	46625
2024	228191	46625
2025	228191	46625
2026	228191	46625
2027	228191	46625
2028	228191	46625
2029	228191	46625
2030	228191	46625

The first step in creating a saved Load Growth Forecast is to fill out the cells that are shaded in light yellow. After doing so, the "Save Active Load Growth" arrow can be selected, and the sheet should update as follows.

The "Save" buttons write the information contained in the spreadsheet to .csv files that are read in by the Python model. If the user has previously saved forecasts that must be modified, they can select the saved forecast from the list and click "Load Saved Load Growth Forecast," which updates the list of net energy and 1 in 2 peaks for the 2016 Toy Forecast.

If the user wants to modify and re-save a case, the user can simply change the values listed in the yellow shaded cells and select the "Save Active Load Growth Forecast" option.

If a case is accidentally deleted from the list of Saved Load Growth Forecasts, the “Refresh Saved Load Growth Forecasts” can be selected to regenerate a list of all previously saved forecasts.

The input generator guides the user through creating inputs and saves inputs into .csv files in the data folder. For each input tab, there is a table on the upper right part of the tab indicating where are the input .csv files located, as shown the example below. The user can also click the link and make changes directly in the .csv file after getting familiar with the tool.

Figure 2-29 Inputs Generator/System Load: An example for links to .csv files

Raw Input File Locations	
Historical Load	S:\E3 Projects\CEC Solar + Storage\model dev\github only tracked\data\system scenario\historical load\2016 CAISO Load.csv
Load Growth Forecast	S:\E3 Projects\CEC Solar + Storage\model dev\github only tracked\data\system scenario\load growth forecasts\E3 Placeholder Forecast.csv

Timeseries data is generally provided in the format of:

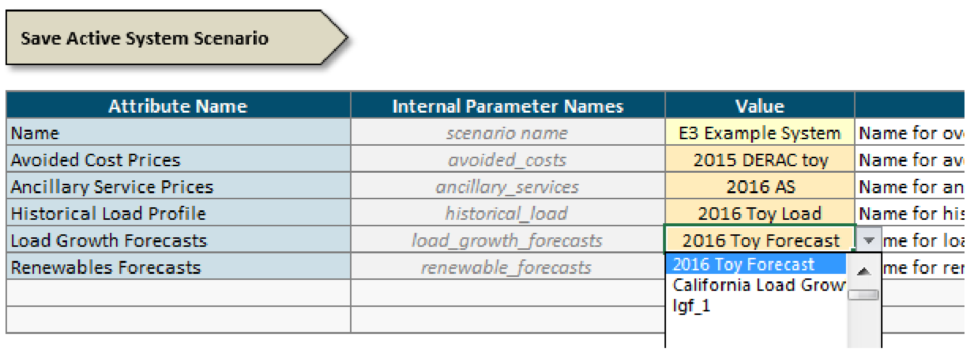
+ Base year (e.g., 2016)
+ Base timeseries (e.g., hourly or 15-minute)
+ Annual escalator (e.g., 0.5%/year)

The inputs interface will escalate the base timeseries for 25 years from the base year and export the data files needed to interface with the Python code. If users need to input multiple years of varying timeseries, users can change the inputs in the .csv files in the corresponding data folder.

2.3.2 SYSTEM SCENARIO

The inputs in this category collectively shape out the scenario for electricity systems, including system marginal avoided costs, marginal emissions, load growth, etc. Inputs in the system scenario category are defined separately in inputs generator first. And later in the Dashboard, user would be asked to create a coherent system scenario by defining which input .csv files to use for each component as shown in the example below:

Figure 2-30 Model Dashboard/0. Case Configuration: System Scenario Set-up



2.3.2.1 Avoided Costs

System benefits included in the model are based on the avoided costs calculation framework in 2018 Avoided Cost Calculator1 published by California Public Utilities Commission (CPUC). Chapter 3.1.1 has detailed descriptions on each avoided cost. The avoided costs categories considered are listed below:

Three system capacity avoided costs are defined as annual values (in units of $/kW-yr):

- System generation
- Transmission
- System average distribution

Five avoided costs are considered as timeseries (in units of $/kWh):

1 HTTP://WWW.CPUC.CA.GOV/GENERAL.ASPX?ID=5267

+ Avoided Losses
+ Avoided Energy
+ Avoided Ancillary Services
+ Avoided Monetized Carbon (Cap and Trade)
+ Avoided GHG Adder

Figure 2-31 Inputs Generator/AC: Example Avoided Costs Input Format

AC Prices Set Name
SCE

Base Year	2016	2016	2016	2016	2016
Default Annual Escalator	0.0%	0.0%	0.0%	0.0%	0.0%

Weather Year	Avoided Losses ($/kWh)	Avoided Energy ($/kWh)	Avoided Ancillary Services ($/kWh)	Avoided Monetized Carbon (Cap and Trade) ($/kWh)	Avoided GHG Adder ($/kWh)
1/1/2017 0:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 1:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 2:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 3:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 4:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 5:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 6:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 7:00	$0.00	$0.00	$0.00	$0.00	$0.00
1/1/2017 8:00	$0.00	$0.00	$0.00	$0.00	$0.00

2.3.2.2 Ancillary Service Market Prices

Four ancillary service price streams can be included as inputs in the tool (in units of $/kWh):

+ Spinning reserve
+ Non-spinning reserve
+ Regulation up reserve
+ Regulation down reserve

Figure 2-32 Inputs Generator/AS: Example Ancillary Service Market Prices Input Format

AS Prices Set Name
2016 AS

Base Year	2016	2016	2016	2016
Default Annual Escalator	0.0%	0.0%	0.0%	0.0%

Weather Year	Spinning Reserve Price ($/kWh)	Non-Spin Price ($/kWh)	Regulation Up Price ($/kWh)	Regulation Down Price ($/kWh)
1/1/16 0:00	0	0	0	0
1/1/16 1:00	0	0	0	0
1/1/16 2:00	0	0	0	0
1/1/16 3:00	0	0	0	0
1/1/16 4:00	0	0	0	0
1/1/16 5:00	0	0	0	0
1/1/16 6:00	0	0	0	0
1/1/16 7:00	0	0	0	0
1/1/16 8:00	0	0	0	0
1/1/16 9:00	0	0	0	0
:	:	:	:	:

2.3.2.3 System Load

System load data is in the form of a historical load shape and a load growth forecast. The load growth forecast is a net energy and a 1-in-2 peak forecast, which will reshape the base historical load shape for each year based on the user's inputs. System load data in the model is used to identify the system peaks and allocate the system capacity avoided costs to peak hours.

Figure 2-33 Inputs Generator/System Load: Example System Load Forecast Input Format

Historical Load Shape Name
2016_load_shape

Load Growth Forecast Name
2016_load_forecast

Historical Load Shape (MW)

Weather Year	Load (MW)
1/1/16 0:00	
1/1/16 1:00	
1/1/16 2:00	
1/1/16 3:00	
1/1/16 4:00	
1/1/16 5:00	
1/1/16 6:00	
1/1/16 7:00	
1/1/16 8:00	
1/1/16 9:00	
:	:

:

Load Growth Forecast

Default Annual Escalator	0.400%	0.400%

Weather Year	Net Energy (GWh)	1-in-2 Peak (MW)
2016	10000	100
2017	*10040*	*100*
2018	*10080*	*101*
2019	*10120*	*101*
2020	*10161*	*102*
2021	*10202*	*102*
2022	*10242*	*102*
2023	*10283*	*103*
:	:	:

2.3.2.4 System Renewables

System-level renewables (bulk, feeder, and total behind-the-meter) are used to calculate the system net load, which feeds into the time-varying value of avoided costs.

Figure 2-34 Inputs Generator/System RE: Example System Renewables Forecast Input Format

System Renewable Energy Name
2016_test

Base Year	2016	2016	2016
Default Annual Escalator	0.0%	0.0%	0.0%

Weather Year	Bulk Renewables (MW)	Feeder Renewables (MW)	Total BTM Renewables (MW)
1/1/16 0:00	0	0	0
1/1/16 1:00	0	0	0
1/1/16 2:00	0	0	0
1/1/16 3:00	0	0	0
1/1/16 4:00	0	0	0
1/1/16 5:00	0	0	0
1/1/16 6:00	0	0	0
1/1/16 7:00	0	0	0
1/1/16 8:00	0	0	0
1/1/16 9:00	0	0	0
:	:	:	:

2.3.2.5 System Fuels

The system fuel scenario defines a set of fuels that will be used if fuel-consuming technologies are active in the case. This section doesn't need to be filled out if users are not interested in the following technologies:

+ Distributed Thermal Generator
+ Detailed Energy Efficiency Measures

For each fuel included in the fuel scenario, the user should provide:

+ Pollutant emissions rates (e.g., CO2, NOx, SOx, PM10)
+ Timeseries fuel price ($/unit: e.g., CO2: tons/MMBTU, NOx and PM10: lbs/MMBTU)

The pollutant emissions rates are used to calculate the onsite emissions due to the DERs; for example, a distributed thermal generator would incur increased local CO2 emissions while offsetting marginal emissions from the bulk electricity system.

Figure 2-35 Inputs Generator/Fuel: Example System Fuels Input Format

System Fuel Prices Scenario Name
test_fuel

System Fuel Emissions Rates

Attribute	Units	oil	gas
CO2 Emissions Rate	*tons/MMBTU*		
NOx Emissions Rate	*lbs/MMBTU*		
PM10 Emissions Rate	*lbs/MMBTU*		

System Fuel Prices ($/MMBtu)

weather year PST hour beginning	oil	gas
1/1/16 0:00	5.70	5.70
1/1/16 0:15	4.94	4.94
1/1/16 0:30	5.18	5.18
1/1/16 0:45	4.90	4.90
1/1/16 1:00	5.49	5.49

2.3.2.6 System Temperature Metric

System temperature metric is used to map similar days across multiple weather years. The remapping functionality will attempt to map similarly ranked temperature days in the same season to each other (respecting weekdays/weekends). The functionality is designed to use:

- Season-month mapping
- Daily ranking metric.

The raw .csv files can be found in the directory:

```
Model directory/data/system scenario/weather/[weather scenario]/
```

2.3.2.7 System Marginal Emissions

In conjunction with the system fuels, the system marginal emissions are used to define the marginal emissions rate of the bulk electricity system for pollutants the user includes.

System marginal emissions can be found in .csv files in the directory:

```
Model directory/data/system scenario/marginal emissions/[emissions scenario name]/
```

2.3.3 DISTRIBUTION SYSTEM

The model collects distribution system information to accurately quantify the impact of DER projects to distribution upgrades. Most of the inputs in this section only matter if users are interested in detailed T&D deferral and interconnection costs calculation. For users who look for more generic avoided distribution costs, the pre-loaded distribution locations can be used.

Potential upgrade information for each distribution technology are collected in “Dist Locations” tab. And after all distribution location is set up, user can move on to “Dist Network” tab to specify the power flow among those distribution locations. The following sections walk through the input set-up in both tabs.

2.3.3.1 Distribution Location

If the user is not interested in quantifying the detailed distribution deferral values, the only input needed is the distribution location load shape. It will be used to convert the annual $/kW-year distribution avoided costs to the hourly price stream. For the other inputs, users will need to fill in placeholder numbers for the model to run through, the values won’t impact other calculations. If the user is interested in quantifying distribution deferral values, the following information is needed. The user is asked first to toggle for the additional features[2], if the user choose FALSE, those input sections are hidden.

For each distribution location, the following information is asked in the input generator tab:

+ Distribution Load Shapes

  Hourly load net of BTM renewables for the location for multiple years. (This is required for all use cases.)

+ Distribution Upgrade Plan (Load Growth Related)

  Load growth related distribution upgrade details including upgrade costs, upgrade threshold, and upgrade impacts. An example is shown in the figure below. (This is only required for detailed T&D deferral feature and Quick T&D Summary.)

Figure 2-36 Inputs Generator/ Distribution Locations: Basic Parameters

**Please note that users should avoid using "_" within the*

Feature	Units	Value
Distribution Location Name		Circuit1102
Include Disbenefits		TRUE
Include Interconnection costs		TRUE

Distribution Project Basic Paramters

Feature	Units	Value
Project Name	*units*	ample_substation_upgra
Project Commission Year	*year*	2019
Defer the project to this year	*year*	2021
Capital Cost	*$*	1000000
Cost Year Basis	*year*	2016
Equipment Type		Primary Feeder
Equipment Inflation Rate	*%/yr*	*2%*
Revenue Requirement Multiplier		*1.7*
O&M Inflation Rate	*%/yr*	*2%*
Book Life	*yrs*	*25*
O&M Factor (Annual O&M$/Project Cos	*%*	*12%*

Equipment Information

[2] Addition features include: 1) considering disbenefits from deferring the investment: the planned upgrade might be able to reduce line losses, but since it is deferred, the losses reduction benefit is also deferred, and 2) including interconnection costs

+ Distribution Upgrade Plan (backflow Related)

  Details for potential distribution upgrades that are related to backflow, including upgrade threshold and upgrade costs. Example is shown below. (Only required for detailed interconnection costs calculation)

Figure 2-37 Inputs Generator/ Distribution Locations: Interconnection Cost Related Inputs

Distribution Detailed Interconnection Cost Parameters

Interconnection Upgrade Project Names
voltage_limit
thermal_limit

Feature	Units	2017	2018
voltage_limit Interconnection Cost	$	1000000	1000000
voltage_limit Export Threshold	kW	10	10
thermal_limit Interconnection Cost	$	1000000	1000000
thermal_limit Export Threshold	kW	100	100
Interconnection Cost	$		
Export Threshold	kW		

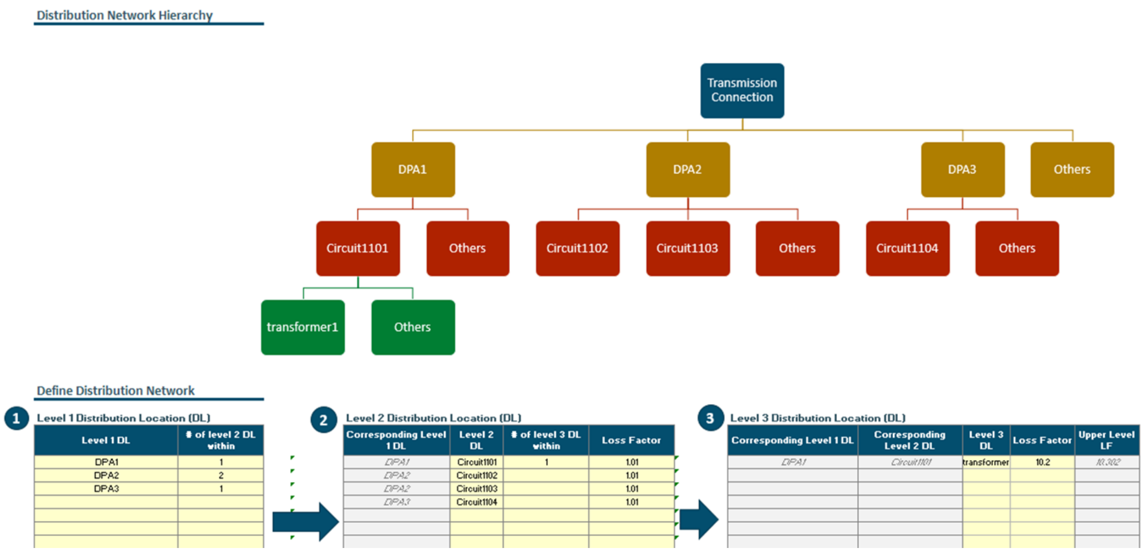
+ Distribution Upgrade Plan (backflow related)

  Details for potential distribution upgrades that are related to backflow, such as upgrade threshold and upgrade costs. An example is shown below. (Only required for detailed interconnection costs calculation.)

2.3.3.2 Distribution Network

The distribution network tables define the relationship between individual distribution locations. User is asked to enter the distribution locations name in the table by hierarchy and specify the loss factors between each connected location. The distribution location names are shown as the dropdown, which is the list of the saved distribution locations in data folders. Distribution location information can be saved into data folders from the “Dist Location” tab. Figure 2-38 below is an example for distribution network setup.

Figure 2-38 Inputs Generator/ Distribution Network: Distribution Network Setup



2.3.4 UTILITY PROGRAMS

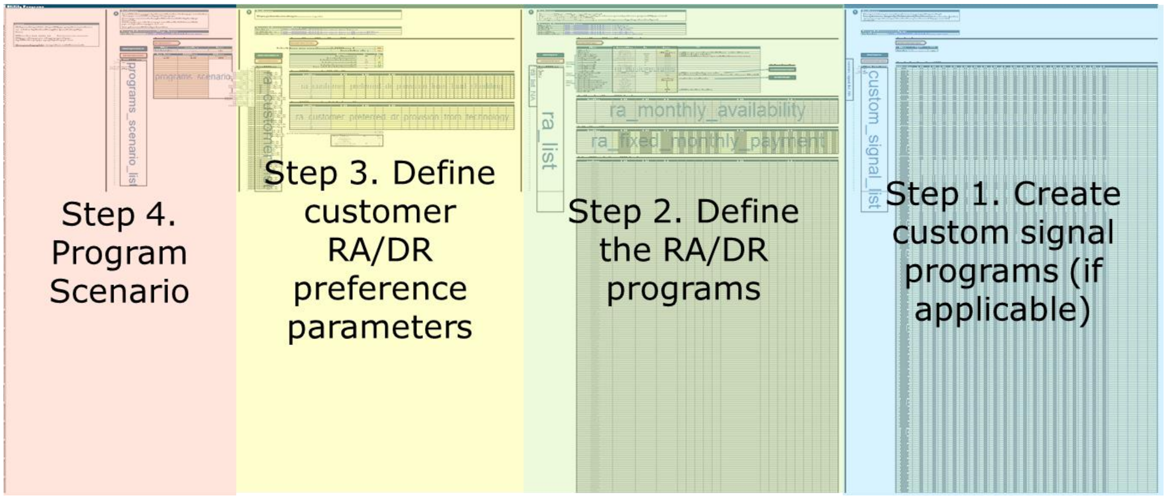
The Solar + Storage tool has been updated to flexibly model a broad range of utility programs that are represented by two program categories in the tool; Custom Signal programs, which are price streams that the customer is rewarded for whenever they dispatch their technologies. And those price streams can be entered at hourly, 15-min, or five-min intervals; and Resource Adequacy (RA) and Demand Response (DR) programs which require load reduction or export during certain hours.

RA is a regulatory construct developed by the CPUC to ensure there is sufficient resource capacity to serve future electricity demand. Three IOUs need to procure enough capacity either by owning the capacity themselves or by contracting with third-parties to meet their capacity requirement. Energy storage is an eligible resource that can be procured to meet utilities' RA requirement. If procured as an RA resource, energy storage will be called upon during certain hours when there is a capacity need. Outside of call hours, the storage asset can operate to gain other revenues.

Unlike an RA program which is mostly eligible for FTM wholesale resources, a DR program allows BTM customers to help the bulk system manage electricity demand by changing their electricity usage during certain hours in response to utility signals. Although eligibility and other regulatory details may differ for RA and DR, the fundamental incentive and penalty mechanisms are very similar. As a result, these two program types are combined into one section where the user can set up both RA and DR programs.

The Utility Programs tab has four main steps and users are encouraged to walk through these in order. Starting from the right side of the sheet users first create any custom signal programs they would like to model, next users define the RA/DR programs, thirdly the customer specific RA/DR parameters are chosen, and finally the user selects which of the available RA/DR and Custom Signal programs created they would like the customer to participate in. At each step, as with other areas of the “Inputs Generator.xlsb” workbook, once a section has been filled out the user must save the changes. Users can load any existing programs present in the data folder on the left side of each section.

Figure 2-39 Inputs Generator/Utility Programs: Tab Structure



2.3.4.1 Custom Signal

A Custom Signal program is a price stream that compensates the customer any time they reduce their load for BTM customers or export to the grid for FTM customers. A Custom Signal program only applies to energy exported by dispatchable technologies (i.e. not solar or load modifiers). This allows users to test innovative price signals, for example a GHG reduction program that sends a real time GHG signal to the customer, compensating them for behavioral change. The custom signal is considered alongside any other revenue streams the customer has access to. The model might decide to ignore the custom signal if it is less lucrative than other revenue streams.

In Step 1 of the ***Utility Programs*** tab users can setup a Custom Signal Program. The user simply enters their 15-min price stream, assigns the program a name and saves the program.

2.3.4.2 Resource Adequacy and Demand Response Programs

The tool can accommodate sophisticated RA/DR program designs. The user first specifies the RA/DR programs parameters (e.g. maximum calls per year, maximum call duration, and incentives), then must specify the relevant RA/DR preference parameters that are specific to the customer. Customer preference parameters may include the maximum kW participation or the portion of their RA/DR provision that comes from load shedding behavior as opposed to dispatching available technologies. This structure enables the same RA/DR program to be used when modelling various customers that might have different preferences for meeting their RA/DR commitments.

Step 2. RA/DR program creation

Step 2 of the Utility Programs tab allows user to create an RA/DR program. An RA/DR program consists of a load reduction commitment, a revenue source, a penalty for not meeting program calls, and a call signal. During a call event the customer is required to reduce load to comply with the load reduction commitment and is compensated for doing so. Failing to meet the load reduction commitment may result in a penalty which reduces the net revenue the customer receives from the RA program.

The load reduction commitment is the kW of load reduction capacity that the customer is committed to deliver and sustain during call events. The load reduction commitment can either be defined by the user ('fixed_by_customer_names') or chosen by the model ('decided_by_model') which can be selected in the RA/DR contract type attribute.

If the user lets the model decide, then the model uses its optimization logic to choose the contract size that maximizes total net revenue based on the program call events, call duration, revenues, penalties, the technologies available to the customer participating in the program, and other non-RA revenue streams available to the customer. If the "fixed_by_customer_names" option is chosen, then the user must define the contract size for the customer participating in the RA program, this is described in step 3.

The RA/DR program can compensate customers through a monthly capacity payment and a volumetric payment (if applicable). For the fixed monthly payment, the user inputs the payment in $/kW-month for the capacity allocated to meet the load reduction commitment in the fixed monthly payment section. If the user includes a volumetric payment, the customer is compensated for every kWh of energy dispatched during call events. A range of options for the volumetric payment can be selected by the user which include various avoided cost streams, and a user defined volumetric payment stream. The user defined volumetric payment is much like a custom signal payment stream except that the customer is only compensated at this rate when dispatching during call events.

Figure 2-40 Inputs Generator/Utility Programs: RA/DR Program Setup - Program compensation options

	Fixed monthly payment toggle	*fixed_monthly_payment*	*Binary*	TRUE
Volumetric Payment options	Volumetric Payment (VP) toggle	*volumetric_payment*	*Binary*	FALSE
	Include system capacity in VP	*vp_include_system_capacity*	*Binary*	FALSE
	Include distribution capacity in VP	*vp_include_distribution_capacity*	*Binary*	FALSE
	Include energy price in VP	*vp_include_energy*	*Binary*	FALSE
	Include emissions price in VP	*vp_include_emissions*	*Binary*	FALSE
	Include TAC signal in VP	*vp_include_TAC*	*Binary*	FALSE
	Include RPS price in VP	*vp_include_RPS*	*Binary*	FALSE
	Include AS prices in VP	*vp_include_AS*	*Binary*	FALSE
	Include user defined signal in VP	*vp_include_user_timeseries*	*Binary*	FALSE

The RA/DR program penalty is applied when the customer does not meet its load reduction commitment by failing to reduce load sufficiently during a call event. Whether a customer has met its load reduction commitment is measured by the quantity of energy delivered during the call event. For example, a 4 hour call for a program with a 10-kW load reduction commitment requires 40 kWh of energy to be dispatched. If the actual energy delivered by the customer is lower than 40 kWh, then a penalty will be applied. There are three penalty options available to the user:

- The “NA” option – This applies a penalty of zero so the customer is not penalized for failing to meet the load reduction commitment. If there is also no volumetric payment then the customer has no incentive to dispatch at all during call events.

- The “per_kwh” option – This is simply a flat $/kWh value that is applied to all energy below the load reduction commitment which can result in penalties exceeding compensation resulting in a net loss of revenue for underperformance.

- The “linear” penalty option allows the model to calculate the penalty that reduces program compensation linearly with performance i.e. if only 50% of the energy is delivered then 50% of compensation is awarded, if 0% of energy is delivered then the customer receives no program compensation. The linear penalty option allows users to understand how valuable the RA/DR program is relative to alternate revenue streams available to the customer.

Whereas setting a very high per_kwh penalty value essentially forces the customer to meet all call events.

Figure 2-41 Inputs Generator/Utility Programs: RA/DR Program Setup – Program penalty options

Contract Penalty Type	ra_contract_penalty_type	NA, linear, per_kwh	linear
User defined contract penalty	ra_contract_penalty_per_kWh	$/kWh	5

The last major set of input parameters required to set up an RA/DR program is the timing of call events. This can either be defined explicitly by the user or defined by the model. Selecting "user_defined" for the signal definition means the user must input a binary timeseries where 1 corresponds to a call event and a 0 represents non call event periods. The length of the call is simply the number of sequential 1's in timesteps. Selecting "program_defintion" for the signal definition means the model decides when call events occur. The user chooses to have call events based on either system load, distribution load, or avoided costs. Once the signal source is selected users are then required to input the total number of calls per year, the maximum allowed calls per month and per day, and the duration of all calls.

Figure 2-42 Inputs Generator/Utility Programs: RA/DR Program Setup – Program call event options

RA signal definition	ra_signal	er_defined or program_definiti	program_definition
Program defined signal - signal source	signal_based_on	Choices	distribution_peak
Program defined signal - number of calls per	calls_per_year	numbers	10
Program defined signal - max calls per month	max_calls_per_month	numbers	10
Program defined signal - max calls per day	max_calls_per_day	numbers	10
Program defined signal - call duration	call_duration	hours	2

Finally, if the program is only run during certain months of the year then this can be selected using the monthly availability input area. All months when the program is not available are ignored in the optimization.

Step 3. Customer RA/DR preference parameters

Step 3 of the Utility Programs tab requires users to define the customer's RA/DR provision parameters. The inputs required vary depending on whether any of the RA programs the customer is participating in have an RA/DR contract type option set to "fixed_by_customer_names'.

If none of the RA/DR programs have an RA/DR contract type option set to "fixed_by_customer_names', then the user only needs to select the customer's maximum load reduction commitment. This input is only important if the user would like to restrict the portion of their dispatchable technology portfolio that they would like to participate in RA. For example, a customer might have a 100 kW four-hour battery but would like to maintain 50 kW for onsite reliability purposes and therefore would prefer to only commit a maximum of 50 kW to RA/DR. When the model selects the contract size for the RA/DR program its decision is then bounded from 0 to 50 kW.

If at least one of the RA/DR programs has an RA/DR contract type option set to "fixed_by_customer_names" then user must specify for each month the total commitment from both load shedding (e.g. turning off lights) and from dispatching technologies like energy storage, EVs, generators, or fuel cells. The size of the commitment should be selected considering the call duration and other technology specific parameters. For example, a customer with a 100 kW four-hour storage asset participating in a DR program with 8 hour call durations should not commit to more than 50 kW of load reduction, as the battery capacity (400 kWh) is insufficient to meet an 8 hour call if supplying more than 50 kW. To support this, the user can input capacities, durations, and round-trip efficiencies of their dispatchable technologies to find out what their maximum commitment should be.

Figure 2-43 Inputs Generator/Utility Programs: Customer RA Program parameters – options for customers where one of the RA programs they are participating in has the "fixed_by_customer_names" contract type

Has the "fixed_by_customer_names" toggle been selected, for ANY DR program?	YES

Description	Unit	Value
Maximum DR provision for customer	kW	45
Maximum possible call duration across all programs	hrs	8
Combined fuel cell and combustion turbine capacity	kW	0
Combined energy capacity of storage related techs	kWh	250
Combined round trip efficiency of storage related techs	%	80%
Reccommended max dispatchable technology contribution	kW	25

2.3.4.3 Programs Scenario

Once the user has created the RA and custom signal programs that they would like to model each program should be added to the Programs Scenario in step 4. A Programs Scenario is a specific set of programs that the user would like a customer to participate in. The user can add an unlimited number of RA and custom signal programs to the Programs Scenario, although more complex programs scenarios tend to have longer running times.

Figure 2-44 Inputs Generator/Utility Programs: Programs Scenario setup

Programs Scenario

Save Programs Scenario

Attribute	Internal Name	Value
Programs Scenario Name	*name*	tpddl_programs

Custom Signal Programs	RA / DR Programs	RA Program Overlap Toggle
custom_signals	*RA_programs*	*program_overlap*
cs_tpddl	lsdr_tpddl	FALSE
cs_1	ra_1	
	ra_2	

When multiple RA programs are in the Programs Scenario the user has the option to select whether, in a situation where two or more RA programs are called at the same time, the customer is compensated for one or all RA programs. If the user would like the customer to be compensated for only one RA program, then they should set the "RA Program Overlap Toggle" to TRUE. The decision as to which program the customer will be compensated for is selected by the tool's optimization logic accounting for compensation and penalties of the various programs. Currently the RA/DR Program Overlap Toggle applies to all RA/DR programs in the Programs Scenario.

2.3.5 CUSTOMERS

Customers are defined by their name and type, as well as VoLL, SAIDI, and SAIFI information. When DG PV size in an individual run is set to "fixed_by_customer_names" in the **Case Configurations** tab, the PV size defined by the customer information will be used. Otherwise, the PV system will be sized to cover a certain % of the customer's annual load.

Customers also include three timeseries:

- Load profile (kW)
- Unitized DG (PV) profile (from 0 to 1)
- Unitized load modifier profile (e.g., aggregate adjustment for EE measures) (sum to 1)

Figure 2-45 Inputs Generator/Customer: Example Customer Input Format

Customer Load Profile (kW)

weather year PST hour beginning	Customer
1/1/17 0:00	257.207
1/1/17 1:00	253.48
1/1/17 2:00	249.855
1/1/17 3:00	248.904

Customer Unitized DG Profile (from 0 to 1)

weather year PST hour beginning	Customer
1/1/15 0:00	0
1/1/15 1:00	0
1/1/15 2:00	0
1/1/15 3:00	0

Customer Unitized Aggregate Load Modifier Profile (total sum to 1)

weather year PST hour beginning	Customer
1/1/15 0:00	0.000015917
1/1/15 1:00	0.000015917
1/1/15 2:00	0.000015917
1/1/15 3:00	0.000015917

2.3.5.1 Customer Detailed Load Modifier Selections

This is an optional input that is only needed if users prefer to look at energy efficiency impacts by measures instead of by an aggregated shape. The additional features provided by the detailed EE feature are listed below:

- Allow separating aggregated EE impacts into multiple EE measures for each customer
- Allow costs and benefits deaffrication among new, replacement on burnout, and retrofit measures
- Allow fuel switching benefits calculation to quantify the fuel usage reduction switching from gas to electric
- Able to select pre-loaded example EE impact shapes from the database

When the "**Detailed EE Measures**" feature toggle is enabled, each EE measure included in the customer's EE selection will have an associated:

- Unitized, static electricity impact shape
- Unitized, static fuel impact shape

Based on these unitized shapes, the impact shapes will be scaled by user-defined annual electricity and fuel savings. For electricity savings, we take the dual baseline approach and calculate the efficient measure's savings relative to:

- Code-standard measures (for new or replace-on-burnout measures)

- Existing measures (for retrofit measures)

The dual baseline approach discounts the benefits of pursuing a retrofit efficiency program after the remaining useful life of the existing measure expires. It is assumed that at the end of the remaining useful life, the existing measure would have been replaced by a code-standard measure.

These scaled impact shapes are then fed through the hourly timeseries calculations such that any coincident electricity or fuel savings will be captured in the final results.

Enabling the Detailed Load Modifiers feature will read the set of Detailed Load Modifier Selections for the customer in each run. This may be a portfolio of lighting measures, HVAC measures, and other measures rather than a single, aggregated load modifier shape. The example inputs for detailed EE are shown below.

Figure 2-46 Inputs Generator/Customer: Example Table for detailed EE

Detailed Customer EE Selection (Optional)

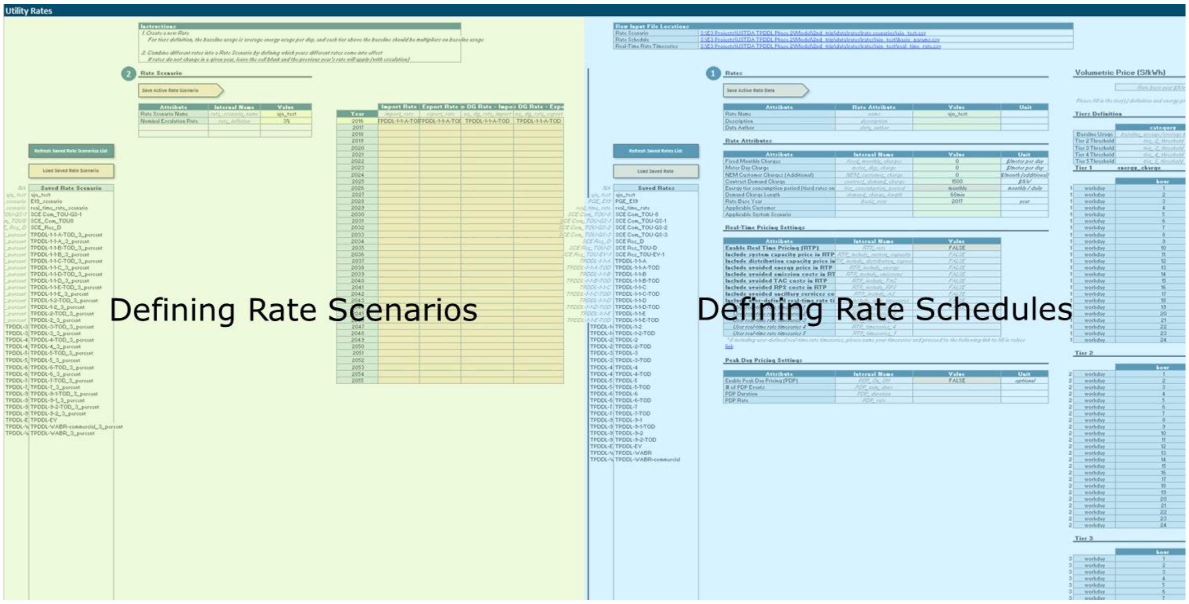
Detailed EE selection is only required if the Detailed EE functionality is enabled for your cases

Load Modifier Name	EE Impact Shape Name	EE Fuel Type	EE Fuel Consumption Impact Shape Name	EE Annual Fuel Reduction (MMBTU)	Replacement Method
lmod_id	*nod_electricity_shape_nam*	*fuel_type*	*od_fuel_impact_shape_na*	*mod_annual_fuel_reductio*	*replacement_method*
Indoor_Linear_Fluorescen	SCE-Res:Indoor_CFL_Ltg	gas	Flat_Impact	0	ROB
Efficient_Air-cooled_Refri	Non_Res:HVAC_Refrig_Cha	gas	Flat_Impact	0	ROB

2.3.6 RETAIL RATE SCENARIOS

Current and future rates that are applied to the hosting customers are defined in two sections in the ***Rates*** tab of the "Inputs Generator.xlsx". As shown in the Figure 2-47 below, on the right-hand side, it is the section for defining rate schedules, such as tiers, energy charges, and demand charges. And on the left-hand side, the rate scenarios section asks user to define the rate changing over years. For example, if TOU periods are expected to be shifted to early evening in 2021, the user should set up two rate schedules in the "Defining Rate Schedules" section for the current rate and the rate in 2021. And then specify the applicable years for corresponding rates in the “Defining Rate Scenarios” section. The following part of the chapter describes these two sections in details.

Figure 2-47 Inputs Generator/Rates: Tab Overview



2.3.6.1 Rate Schedules

There are three sections in the rate schedule inputs:

General Rate Attributes and Fixed Charges:

This section includes general rate attributes like rate base year and demand charge billing length as well as the fixed charges. Prices in the tool are all nominal if there are no special notes, and the rates are inflated to the nominal level based on the rate base year.

Volumetric Charges

Volumetric charges can be specified in the following three ways

- Common Energy Charges

  The most common one is specifying energy charges in two 24 hours * 12 months matrixes. The user can specify energy charges for weekday and weekends at each hour for each month as shown in the figure below. Users can also model tiered rates by specifying baseline usage kWh for each month and the relevant threshold for moving from one tier to the other. Energy charges for tier 2, 3, and 4 can be specified below the tier 1 tables.

Figure 2-48 Inputs Generator/Rates: Rate Schedule – Energy Charges

Volumetric Price

Rate base year $/kWh

Please fill in the tier(s) definition and energy price for the following hour of the day and time of the year

Tiers Definition

	category	January	February	March	April	May	June	July	August	September	October	November	December
Baseline Usage	*baseline_useage (average kWh/day)*												
Tier 2 Threshold	*tier_2_threshold*												
Tier 3 Threshold	*tier_3_threshold*												
Tier 4 Threshold	*tier_4_threshold*												

Tier 1 **energy_charge**

	hour	January	February	March	April	May	June	July	August	September	October	November	December
workday	1	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	2	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	3	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	4	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	5	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	6	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	7	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	8	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	9	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	10	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	11	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	12	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	13	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	14	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	15	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	16	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	17	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	18	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	19	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	20	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	21	0.23689	0.23689	0.23689	0.23689	0.23689	0.37132	0.37132	0.37132	0.37132	0.23689	0.23689	0.23689
workday	22	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	23	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003
workday	24	0.13003	0.13003	0.13003	0.13003	0.13003	0.12927	0.12927	0.12927	0.12927	0.13003	0.13003	0.13003

- Real-Time Pricing

  Users can also choose to model a real time rate by linking the rates to avoided costs and/or adding in a user-defined hourly rate. Note that the real time pricing option overwrites the energy charges specified in the previous common energy charges section. However, if there are demand charges included in this rate schedule the demand charges are still applicable.

Figure 2-49 Inputs Generator/Rates: Rate Schedule – Real-time Pricing

Real-Time Pricing Settings

Attribute	Value
Enable Real Time Pricing (RTP)	TRUE
Include system capacity price in RTP	TRUE
Include distribution capacity price in RTP	TRUE
Include avoided energy price in RTP	TRUE
Include avoided emission costs in RTP	TRUE
Include avoided TAC costs in RTP	TRUE
Include avoided RPS costs in RTP	TRUE
Include avoided ancillary services costs in RTP	TRUE
Include user-defined real-time rate timeserie:	TRUE

+ Peak Day Pricing
+ Peak day pricing can be added to the common energy charges when this feature is enabled. Users specify # of peak events and their duration, and the model swaps out the regular energy charges with peak rates specified in this section for the highest system avoided cost hours.

Figure 2-50 Inputs Generator/Rates: Rate Schedule – Peak Day Pricing

Peak Day Pricing Settings

Attribute	Value	Unit
Enable Peak Day Pricing (PDP)	FALSE	*optional*
# of PDP Events		
PDP Duration		
PDP Rate		

Demand Charges

Demand charges are specified in a similar manner as common energy charges in 24 hours * 12 months matrixes. Users specify the $/kW demand charges in the hours and months that the demand charges are applied to. In the example below, $20/kW demand charge is applied to the workday peak over 24 hours for January, and in February, $10/kW is charged to the peak occurring between 9 am and 5 pm on workdays.

Figure 2-51 Inputs Generator/Rates: Rate Schedule – Demand Charge

	hour	January	February
workday	1	20	
workday	2	20	
workday	3	20	
workday	4	20	
workday	5	20	
workday	6	20	
workday	7	20	
workday	8	20	
workday	9	20	10
workday	10	20	10
workday	11	20	10
workday	12	20	10
workday	13	20	10
workday	14	20	10
workday	15	20	10
workday	16	20	10
workday	17	20	10
workday	18	20	
workday	19	20	
workday	20	20	
workday	21	20	
workday	22	20	
workday	23	20	
workday	24	20	

A total of four demand charge levels are included in the input settings to accommodate complicated TOU demand charges. Each demand charge level is additive.

2.3.6.2 Rate Scenarios

A rate scenario represents the expected future rate schedules for the hosting customer. In the example below, this rate scenario starts with SCE TOU-GS rate and switch to TOU-8 at year 2023. The 3% escalation rate is applied to TOU-GS rate from 2017 to 2022 and to TOU-8 from 2024 onward.

Figure 2-52 Inputs Generator/Rates: Rate Scenarios

Rate Scenario

Save Active Rate Scenario

Attribute	Internal Name	Value
Rate Scenario Name	*rate_scenario_name*	SCE Com_TOU-GS-1
Nominal Escalation Rate	*rate_inflation*	3%

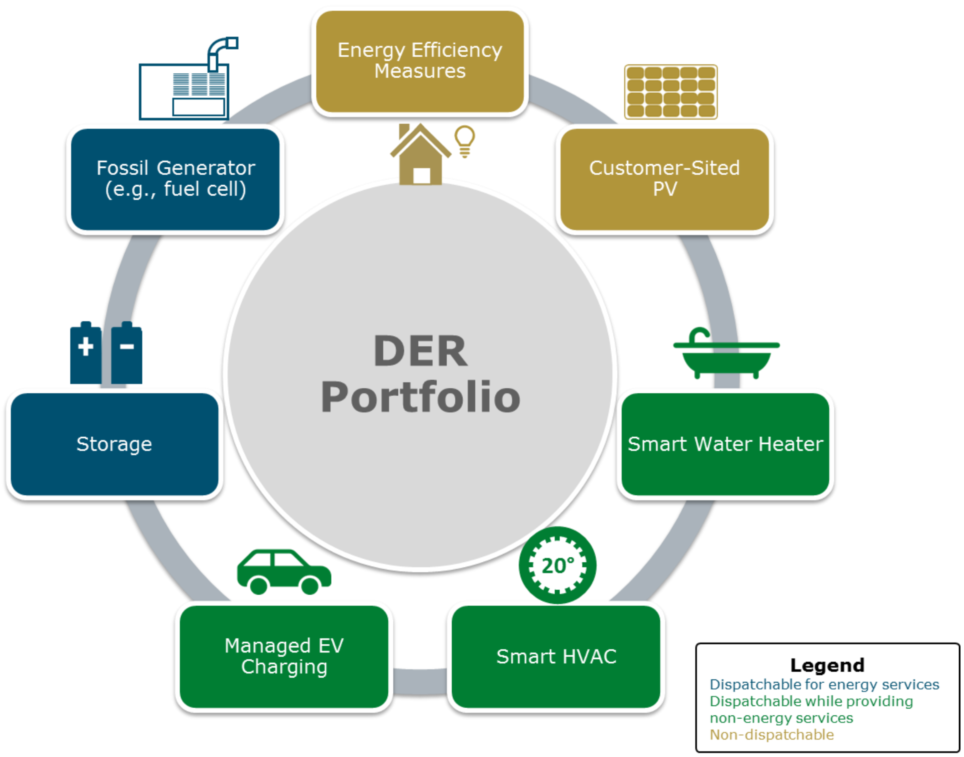
	Import Rate	Export Rate	No DG Rate
	import_rate	*export_rate*	*no_dg_rate*
2016	SCE Com_TOU-GS-1	SCE Com_TOU-GS-1	SCE Com_TOU-GS-1
2017			
2018			
2019			
2020			
2021			
2022			
2023	SCE Com_TOU-8	SCE Com_TOU-8	SCE Com_TOU-8
2024			
2025			
2026			
2027			
2028			

2.3.7 TECHNOLOGIES

The Solar + Storage Tool is designed with a focus on evaluating solar + storage projects; however, the tool can also be used to dispatch various other “smart” technologies. The economic dispatch of these technologies is constrained by a set of technical characteristics for each technology type and controlled by either utility avoided costs or customer retail rates. These technologies include:

+ Energy Efficiency Measures
+ Storage
+ Managed EV Charging
+ Customer-Sited Fuel Cell Generators
+ Smart HVAC
+ Smart Water Heater

Figure 2-53 Technologies Available in Solar + Storage Tool



2.3.7.1 Energy Efficiency Measures (Detailed EE Measures)

The model is pre-loaded with generic energy efficiency shapes for three IOUs in the ***EE Shapes*** tab. Users can add new electricity and fuel impact shapes to the database by following the instructions in the ***EE Shapes*** tab.

When the "Detailed EE Measures" feature toggle is enabled, users also need to specify each EE measure included in the customer's EE selection.

2.3.7.2 Energy Storage

Storage devices such as lithium-ion batteries can be defined in the ***Tech Storage*** tab. The main operating characteristics of the storage device are:

- Power capacity
- Energy capacity
- Roundtrip efficiency
- Parasitic losses
- Minimum state-of-charge

Storage device's costs and financing information is also specified in this tab, including capital costs, O&M costs, SGIP availability, etc.

2.3.7.3 Managed Electric Vehicle Charging

The Solar + Storage Tool can optimize the optimal charging and discharging – if Vehicle to Grid (V2G) is enabled – schedule for EV, given its driving constraints to minimize overall onsite net costs. Results compare the benefits of a more advanced EV management – managed EV charging (V1G) or V2G – to an unmanaged baseline charging load.

The following vehicle technical characteristics are needed for the analysis:

- Maximum charge rate (considering charger charge rate)
- Vehicle battery capacity (kWh)
- Charging efficiency
- Discharge efficiency (back to grid)
- Parasitic losses

- Minimum state-of-charge

In addition to technical characteristics, the EV is associated with a set of customer driving parameters. This list of parameters is associated with the customer users previously created, and include:

- Customer driving schedule in kW
- Probability for customer to drive further than scheduled distance
- Customer charging availability
- Customer baseline (unmanaged) charging profile in kW

2.3.7.4 Distributed Thermal Generator

The distributed thermal generator technology can be used to model diesel generator or other fuel-consuming devices. The main technical characteristics of the thermal generator are:

- Heat rate
- Maximum power rating
- Ramp rate
- Generator maintenance derating factors
- Minimum stable level
- Minimum up and down time
- Whether it is a must run unit

Given the dispatch characteristics of the technology, the Solar + Storage Tool will create a unit commitment schedule and dispatch the unit economically.

2.3.7.5 Smart Water Heater

Similar to optimizing electric vehicle's charging behavior, the model optimizes water heater electricity usages based on the customer's water consumption pattern. Water heater related inputs are also separated into two sections:

- Water heater technical characteristics
    - Water tank capacity and losses
    - Ambient and water temperature
    - Maximum power for heating element and heat pump (if applicable)
- Customer water usage preference
    - Scheduled water usage
    - Probability of using more water in additional to the scheduled one
    - Water heater baseline (unmanaged) usage

2.3.7.6 Smart HVAC

Modeling a "smart HVAC system" is also similar to modeling a smart water heater and electric vehicle. The model optimizes the operation of the HVAC system to minimize the electricity bills but at the same time maintain the temperature within onsite comfort zones. HVAC system technical characteristics, customer house information, and customer preferences are needed for input:

- Technical characteristics:
    - HVAC Heating and AC SEER Rating
    - Economizer Sizing Metric and Power Factor
- House information

    - Roof area, walls surface areas, azimuth, window area, etc.
    - Building air infiltration rate, thermal mass, ceiling height, etc.
    - Local weather data (e.g., temperature, humidity, etc.)
- Customer preference
    - Setting temperature for heating and AC
    - Temperature deviation penalty
    - Baseline (unmanaged) usage before optimizing

If users have an existing impact shape to represent the smart HVAC, they can use the aggregated load modifier or detailed EE feature to calculate the cost effectiveness.

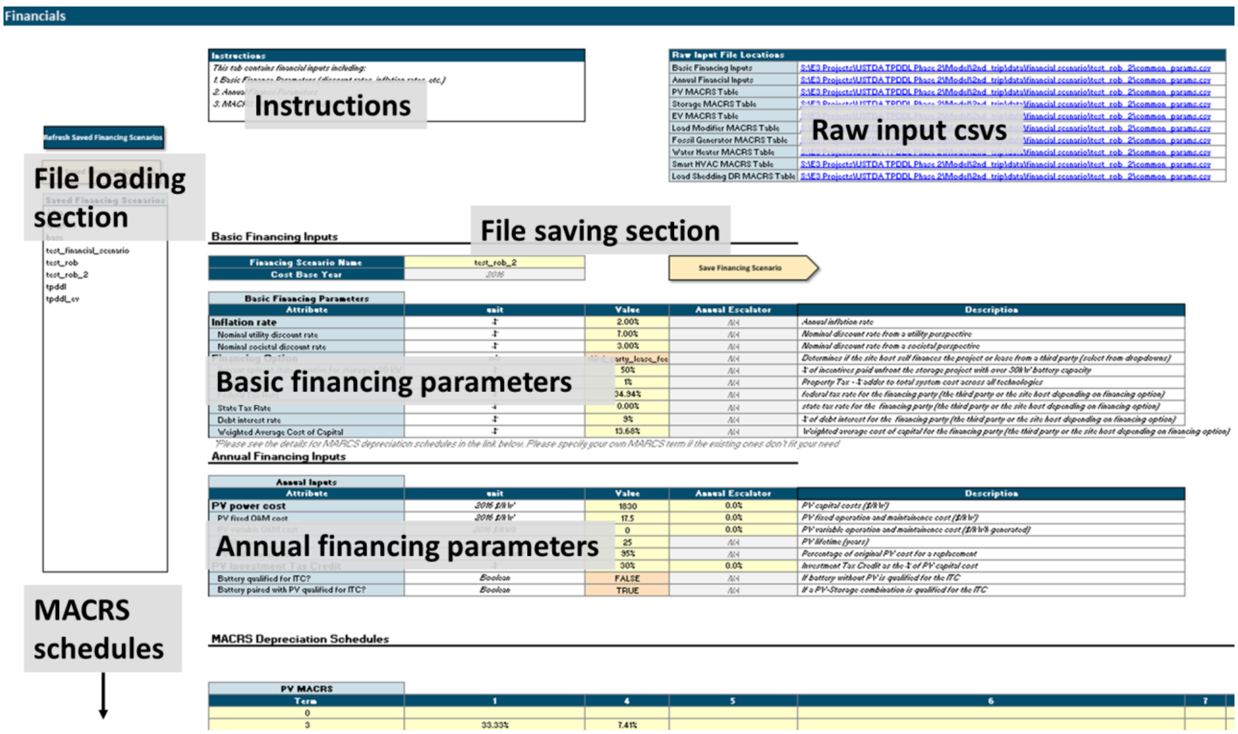
2.3.8 FINANCIALS

The financial information in the tool are split into two separate sections

- General financial information and financial information for the non-dispatchable technologies (PV, Demand Response) in the "Financials" tab
- Technology specific financial information located in "Tech Storage", "Tech FG", "Tech EV", "Tech HVAC", "Tech WH" tabs

2.3.8.1 Financials Tab

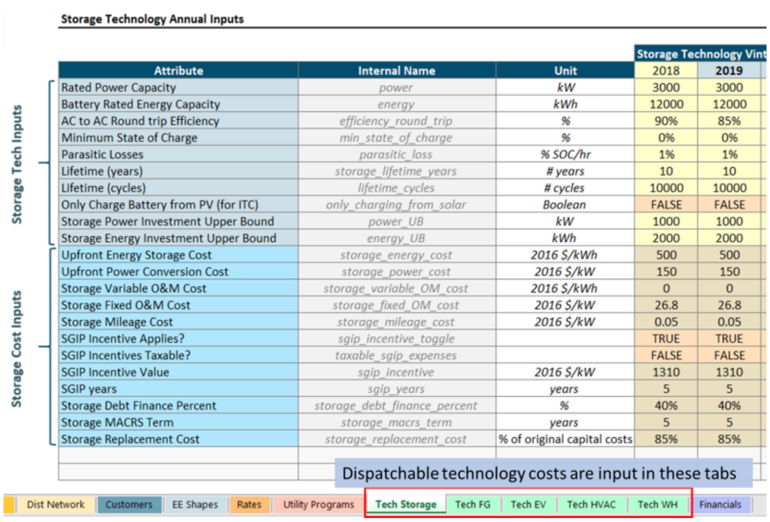
Figure 2-54 Inputs Generator/Financials: Example Storage Financial Parameters Inputs Format



The ***Financials*** Tab is used to save three types of financial inputs. Finance parameters such as discount rates and inflation which are common across all technologies, cost inputs for non-dispatchable technologies, such as PV, load modifiers and load-shedding demand response, and MACRS information. Figure 2-54 shows the different sections of the financials tab. The file loading and file saving sections are used to load parameters from different financial scenarios into the raw input .csv files. The Basic financing parameters section contains parameters that apply across all years of a run. Example parameters include a property tax, discount rates and a base year for financial analysis. The Annual financing parameters section contains financial inputs that vary by year. The user can make edits in the cells to save different values for a base year and can use the annual escalator column to escalate base year values across all years of a run. However, if the user would like more control over the specific annual values for parameters, the user can edit them in detail in the .csv files in the data folders. The MACRS sections includes depreciation schedules that the user can input for different technologies. After all inputs have been filled out, the user can save and load financial scenarios using the buttons in the file saving / loading section as detailed above. In addition, for more control, the user can click the links in the raw input .csv files to manually change any values necessary.

Technology Costs

Figure 2-55 Inputs Generator/Individual Technology Tabs: Dispatchable technology inputs



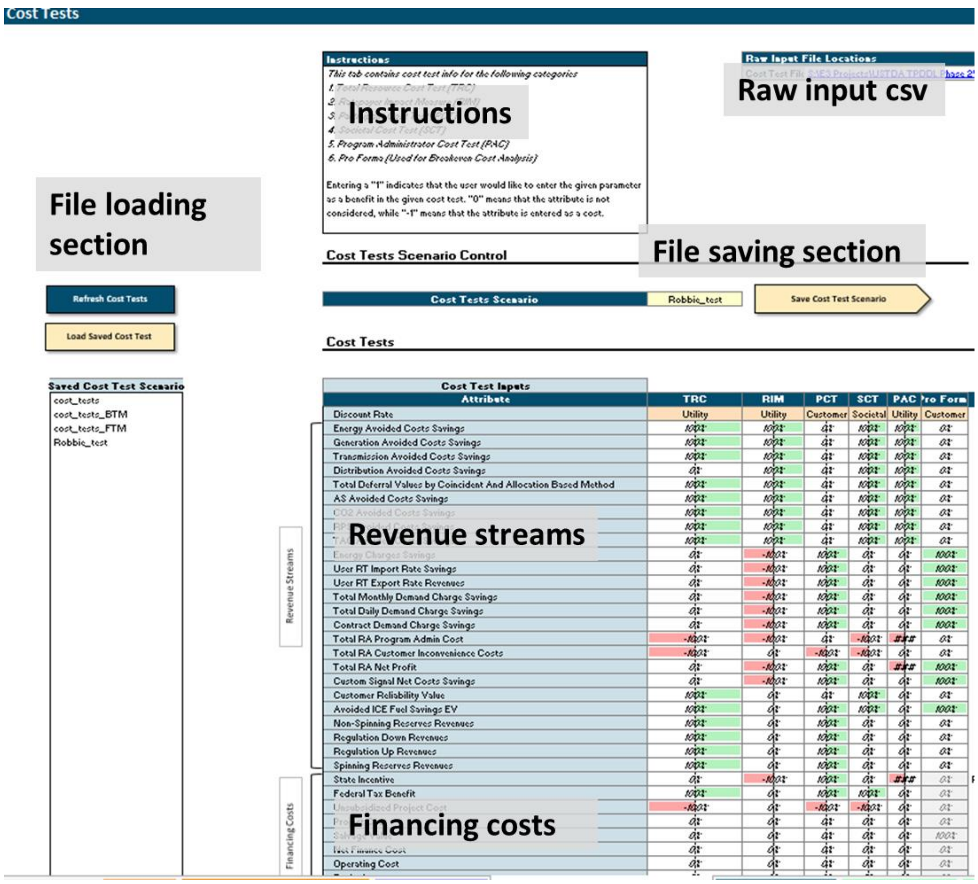
Storage Technology Annual Inputs

			Storage Technology Vint	
Attribute	Internal Name	Unit	2018	2019
Rated Power Capacity	power	kW	3000	3000
Battery Rated Energy Capacity	energy	kWh	12000	12000
AC to AC Round trip Efficiency	efficiency_round_trip	%	90%	85%
Minimum State of Charge	min_state_of_charge	%	0%	0%
Parasitic Losses	parasitic_loss	% SOC/hr	1%	1%
Lifetime (years)	storage_lifetime_years	# years	10	10
Lifetime (cycles)	lifetime_cycles	# cycles	10000	10000
Only Charge Battery from PV (for ITC)	only_charging_from_solar	Boolean	FALSE	FALSE
Storage Power Investment Upper Bound	power_UB	kW	1000	1000
Storage Energy Investment Upper Bound	energy_UB	kWh	2000	2000
Upfront Energy Storage Cost	storage_energy_cost	2016 $/kWh	500	500
Upfront Power Conversion Cost	storage_power_cost	2016 $/kW	150	150
Storage Variable O&M Cost	storage_variable_OM_cost	2016 $/kWh	0	0
Storage Fixed O&M Cost	storage_fixed_OM_cost	2016 $/kW	26.8	26.8
Storage Mileage Cost	storage_mileage_cost	2016 $/kW	0.05	0.05
SGIP Incentive Applies?	sgip_incentive_toggle		TRUE	TRUE
SGIP Incentives Taxable?	taxable_sgip_expenses		FALSE	FALSE
SGIP Incentive Value	sgip_incentive	2016 $/kW	1310	1310
SGIP years	sgip_years	years	5	5
Storage Debt Finance Percent	storage_debt_finance_percent	%	40%	40%
Storage MACRS Term	storage_macrs_term	years	5	5
Storage Replacement Cost	storage_replacement_cost	% of original capital costs	85%	85%

Technology specific costs for dispatchable technologies (Storage, Fossil Generator, EV, HVAC, WH) can be found in the technology tabs as shown in Figure 2-55. The user can enter cost values for the technology in the cost section and these are saved to the .csv file associated with each technology, rather than the financial scenario folder.

2.3.9 COST TEST DEFINITION

Figure 2-56 Inputs Generator/Cost Test Definitions



The ***Cost Tests*** tab determines if outputs from the optimization and financial analysis are considered costs or benefits under different cost-test perspectives. The user can enter values between -1 and 1 for each attribute under the six different cost- test perspectives (Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), Participant Cost Test (PCT), Societal Cost Test (SCT), Program Administrator Cost Test (PAC), or a Pro Forma Perspective, which is used to calculate costs and benefits used in project financing). If the user enters a positive value, the stream is a benefit, while if the user inputs a negative value, the stream is a cost. For example, if the optimization outputs an

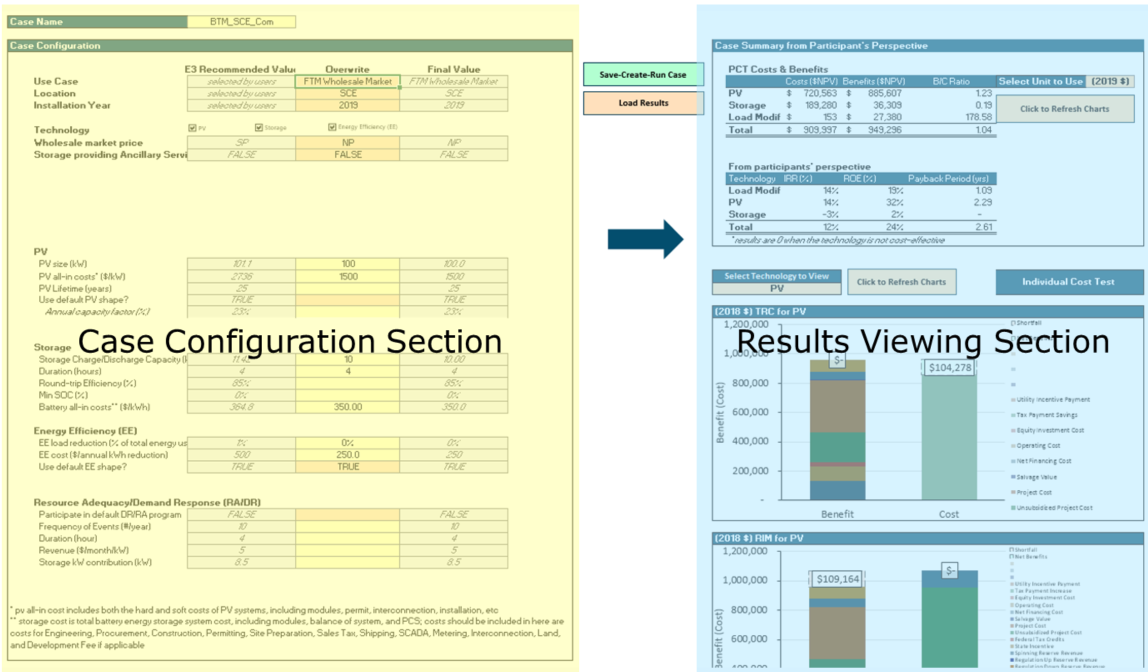
“Energy Avoided Cost Savings” value of $1,000, the user can enter 0.9 under the TRC column and 0 under the PCT column, which indicates that this stream results in a benefit of $900 under the TRC perspective and a $0 benefit under a PCT perspective. Once all inputs are entered, the user can use the file-saving and file-loading sections to save the data into the relevant .csv files. Note that pro forma financing inputs are not changeable, financing costs are calculated with using the methodology specified in section 3.2.

2.4 PV + Storage Simplified UI

The “PV + Storage Simplified UI” is designed for the users who are not familiar with the tool and would like to set up a case and see the results within half an hour. This UI includes the most common revenue streams and use cases, including BTM bill savings, FTM wholesale market participation, demand response program, and resource adequacy programs. It leverages default inputs in the database and allows users to change some of the key inputs (e.g., utility rates, PV size, storage size, etc.) to customize the analysis for their projects.

This simplified UI only has one tab for users to modify and interact with. The case configuration section is on the left and the results viewing section is on the right. After setting up the cases on the left side, users can click the two buttons in the middle to run and case and load the results. After the case is defined, running the cases and loading in the results will take less than five minutes. The following chapter describes the case set up process, results viewing section, and the feature limitations for this UI.

Figure 2-57 Solar + Storage Simplified UI Overview



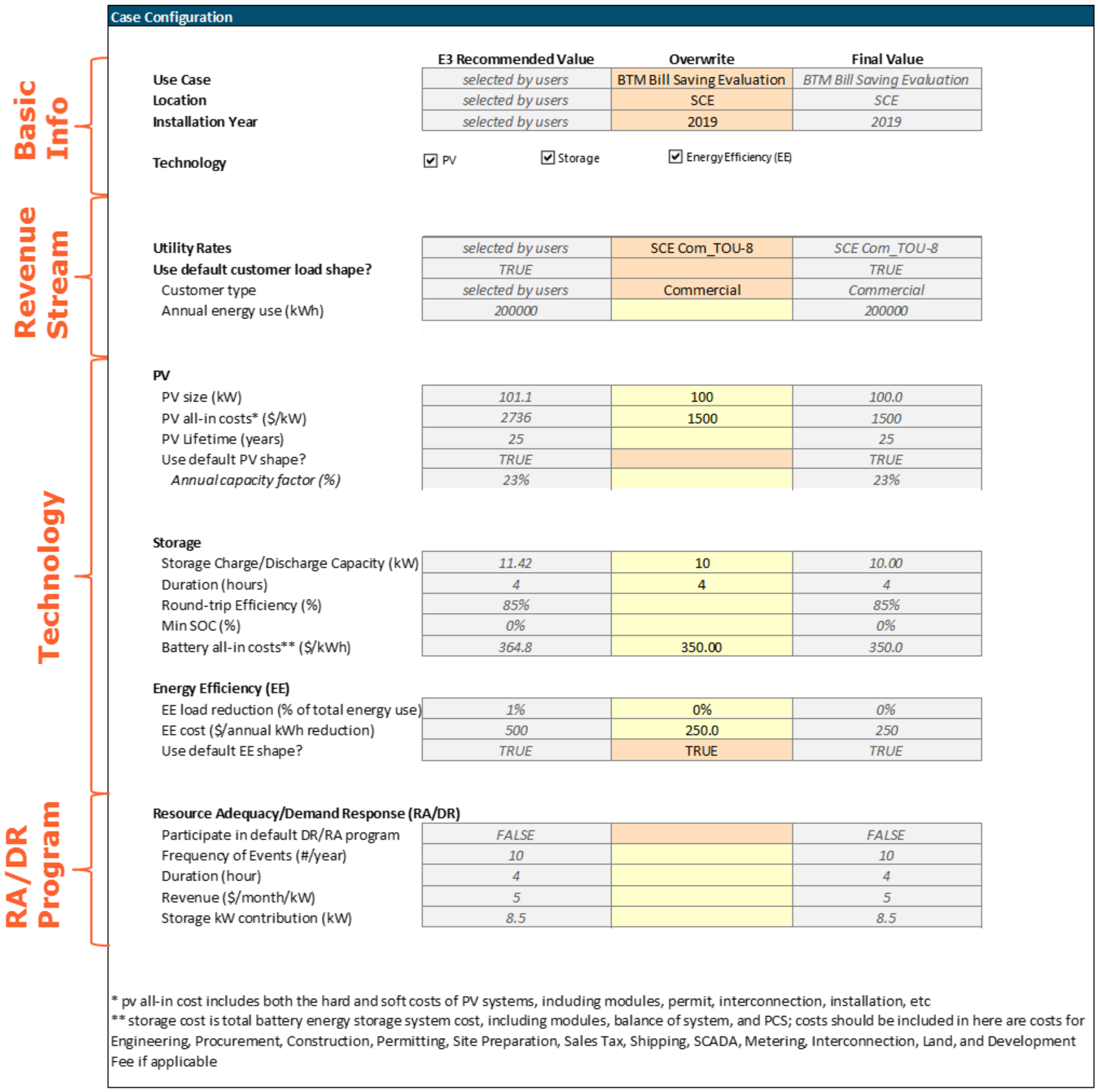
2.4.1 CASE SETUP SECTION

The case configuration section is shown in the There are three columns for each input in the case configuration section: E3 Recommended Value, Overwrite, and Final Value. The E3 Recommended Value column shows the values recommended by E3 based on users' previous selection on use case, project locations, and customer load information (if applicable). This is meant to provide some ballpark numbers for users who are less familiar with evaluating solar + storage projects. Users can overwrite the recommended values in the overwrite columns. The final values are displayed on the third column.

Figure 2-58 below. It can be broken down into four sections: Basic Info, Revenue Streams, Technology, and RA/DR programs. The basic info section asks for inputs like targeted use cases, project location, installation year, and technology choice. The remaining sections will show up dynamically according to the user selection in Basic Info section. For example, if the BTM bill savings evaluation use case is chosen, the customer rates and default customer load shape input sections show up. And if the user chooses FTM wholesale market evaluation as the use case, the customer load and utility rates will be hidden and the wholesale market prices selection will show up. Demand Response/Resource Adequacy Programs are only available when storage technology is selected in the portfolio.

There are three columns for each input in the case configuration section: E3 Recommended Value, Overwrite, and Final Value. The E3 Recommended Value column shows the values recommended by E3 based on users' previous selection on use case, project locations, and customer load information (if applicable). This is meant to provide some ballpark numbers for users who are less familiar with evaluating solar + storage projects. Users can overwrite the recommended values in the overwrite columns. The final values are displayed on the third column.

Figure 2-58 PV + Storage Simplified UI: Case Configuration



Case Configuration

Basic Info

	E3 Recommended Value	Overwrite	Final Value
Use Case	*selected by users*	BTM Bill Saving Evaluation	*BTM Bill Saving Evaluation*
Location	*selected by users*	SCE	*SCE*
Installation Year	*selected by users*	2019	*2019*

Technology ☑ PV ☑ Storage ☑ Energy Efficiency (EE)

Revenue Stream

	E3 Recommended Value	Overwrite	Final Value
Utility Rates	*selected by users*	SCE Com_TOU-8	*SCE Com_TOU-8*
Use default customer load shape?	*TRUE*		*TRUE*
Customer type	*selected by users*	Commercial	*Commercial*
Annual energy use (kWh)	*200000*		*200000*

Technology

	E3 Recommended Value	Overwrite	Final Value
PV			
PV size (kW)	*101.1*	100	*100.0*
PV all-in costs* ($/kW)	*2736*	1500	*1500*
PV Lifetime (years)	*25*		*25*
Use default PV shape?	*TRUE*		*TRUE*
Annual capacity factor (%)	*23%*		*23%*
Storage			
Storage Charge/Discharge Capacity (kW)	*11.42*	10	*10.00*
Duration (hours)	*4*	4	*4*
Round-trip Efficiency (%)	*85%*		*85%*
Min SOC (%)	*0%*		*0%*
Battery all-in costs** ($/kWh)	*364.8*	350.00	*350.0*
Energy Efficiency (EE)			
EE load reduction (% of total energy use)	*1%*	0%	*0%*
EE cost ($/annual kWh reduction)	*500*	250.0	*250*
Use default EE shape?	*TRUE*	TRUE	*TRUE*

RA/DR Program

	E3 Recommended Value	Overwrite	Final Value
Resource Adequacy/Demand Response (RA/DR)			
Participate in default DR/RA program	*FALSE*		*FALSE*
Frequency of Events (#/year)	*10*		*10*
Duration (hour)	*4*		*4*
Revenue ($/month/kW)	*5*		*5*
Storage kW contribution (kW)	*8.5*		*8.5*

* pv all-in cost includes both the hard and soft costs of PV systems, including modules, permit, interconnection, installation, etc
** storage cost is total battery energy storage system cost, including modules, balance of system, and PCS; costs should be included in here are costs for Engineering, Procurement, Construction, Permitting, Site Preparation, Sales Tax, Shipping, SCADA, Metering, Interconnection, Land, and Development Fee if applicable

Figure 2-59 PV + Storage Simplified UI: Revenue section when "FTM Wholesale Market" Use Case is Chosen

	E3 Recommended Valu	Overwrite	Final Value
Use Case	*selected by users*	FTM Wholesale Market	*FTM Wholesale Market*
Location	*selected by users*	SCE	*SCE*
Installation Year	*selected by users*	2019	*2019*
Technology	☑ PV	☑ Storage	☑ Energy Efficiency (EE)
Wholesale market price	*SP*	NP	*NP*
Storage providing Ancillary Servi	*FALSE*	FALSE	*FALSE*

After all the inputs are entered and the case is named, users can click “Save-Create-Run” Case and the model will start running. The case set up from this UI usually takes a couple of minutes to finish.

Many assumptions are made ahead of the time to simplify the process of setting up cases in the PV + Storage Simplified UI. If the user is interested in checking all the underlying assumptions, input .csv files that are used for the case are saved in `cases/[case name]/inputs/snapshot/`.

2.4.2 RESULTS VIEWING SECTION

This simplified UI display some of the most important and popular results for solar + storage case, including:

+ Participant Cost Effectiveness Summary

  A high-level summary on project cost effectiveness from an investor (FTM) or customers’ perspective (BTM). It provides summaries on total costs, total benefits, benefit and cost ratios, IRR, return on equity ROE, and payback period for participants by technologies.

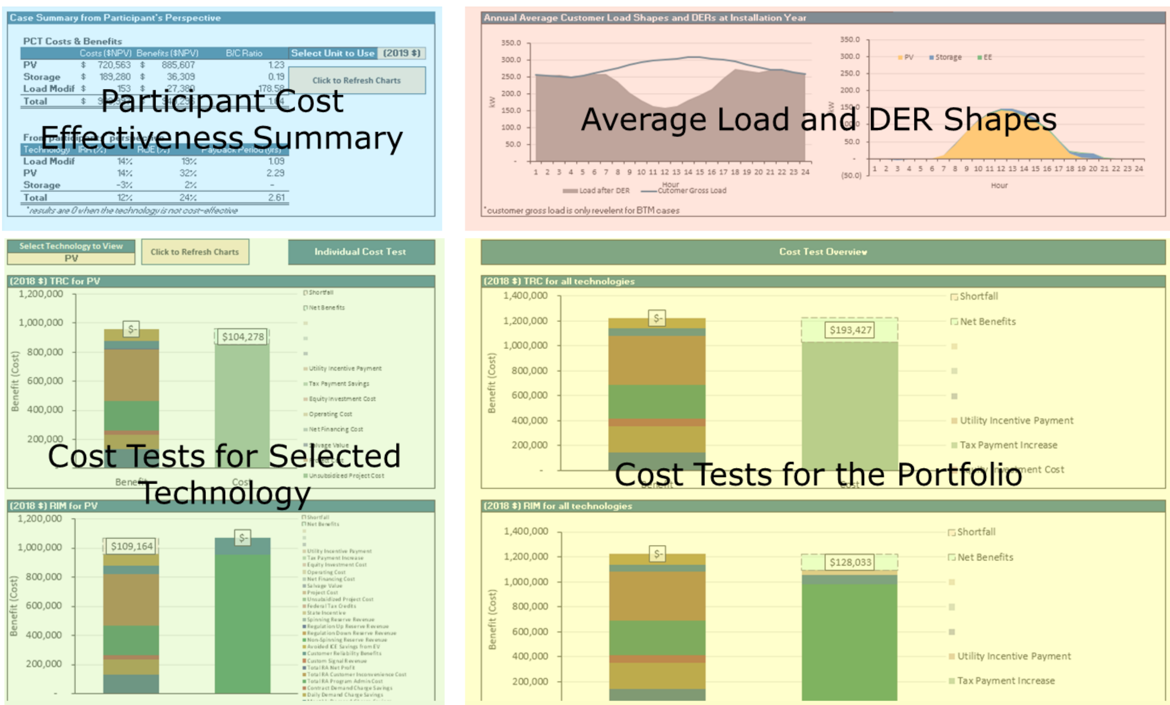
+ Average Load and DER Shapes

  Annual average daily DER and customer load (if applicable) shapes

+ Cost Tests

Total Resource Cost Test (TRC), Participant Cost Test (PCT), Rate Impact Measure (RIM) Test, and Program Administrative Cost Test (PAC) are shown for each individual technology as well as the portfolio with all of the technologies combined.

Figure 2-60 PV + Storage Simplified UI: Results Viewing Section



If users are interested in seeing more results(e.g. daily dispatch charts for each technology) the case initiated in this simplified UI can also be loaded into the "Model Dashboard.xlsb" for results viewing.

2.4.3 FEATURE LIMITATION

This UI is designed for solar + storage use cases and can only perform the analysis with a subset of features. If more comprehensive features are needed, users can follow the standard case set up instruction and use the “Model Dashboard” and “Inputs Generator” UIs for initiating cases and viewing results.

Features that are NOT available in this simplified interface are summarized below:

+ Technology:

  Detailed EE, fuel cell generation, smart EV charging, EV cost effectiveness analysis, smart water heater, smart HVAC, and load shedding DR analysis

+ Revenue Streams:

  Distribution deferral values, customized utility programs, real time rate, customized rates, customized customer reliability values

+ Model toggles

  Fast optimization selection, optimization window selection, and optimization interval selection

2.5 Distribution Values Screening UI

The “Distribution Values Screening UI” is designed for the users who are interested in targeting DER technologies for non-wires alternatives (NWAs) and distribution deferral values. For example, utility staffs who are preparing for Distribution Deferral Opportunity Report (DDOR) filings can use this UI to calculate marginal distribution avoided costs for distribution locations that have deferral potential. Furthermore, developers who are preparing for an NWA Request for Proposal (RFP) can also use this to screen for the valuable distribution locations and suitable technologies.

This UI provides two screenings; the first one is a distribution hotspots screening. This screening provides quick summaries on marginal distribution avoided costs in $/kW-yr for all distribution locations that are saved in the database. The marginal distribution avoided costs are calculated based on distribution upgrade costs, deficiency, target deferral years, and discount rates. Realized distribution deferral based on the DER technology's dispatch and impact shapes are not calculated in this screening. Default distribution upgrade information at three distribution locations are included in the default database. New distribution upgrade inputs can be added in the ***Dist Locations*** and ***Dist Network*** tabs in the "Inputs Generator" UI. In the "Inputs Generator UI", users need to enter expected upgrade costs, distribution hourly load, load growth, deficiency, and the distribution system topology. Instructions on entering distribution inputs are in Chapter 2.3.3.

The second screening is for technology. This screening calculates the total system values provided by selected DER technologies using default technology characteristics. This is meant to help users get a ballpark estimate on the values and then prioritize the cost-effective technologies without having to define technology characteristics for all of them. The screening provides a comparison on system benefits that are provided by each technology on the levelized $/kWh basis. Users can select the desired distribution locations and technologies for screening. Distribution values can be calculated based on a simple marginal distribution avoided cost figure or based on the realized distribution deferral. The realized distribution deferral can be estimated using distribution upgrade costs, deficiency, and load forecasts or by using a simple marginal distribution.

In the NWA evaluation, after screening for the high value locations and suitable technologies, the third step is to simulate the operation and evaluate the portfolio using accurate DER technology characteristics. The detailed evaluation can be set up through the standard case set up process. If the users turn on the "Distribution: Detailed T&D Deferral" in the feature toggles, the distribution deferral values will be calculated based on the potential upgrade project information.

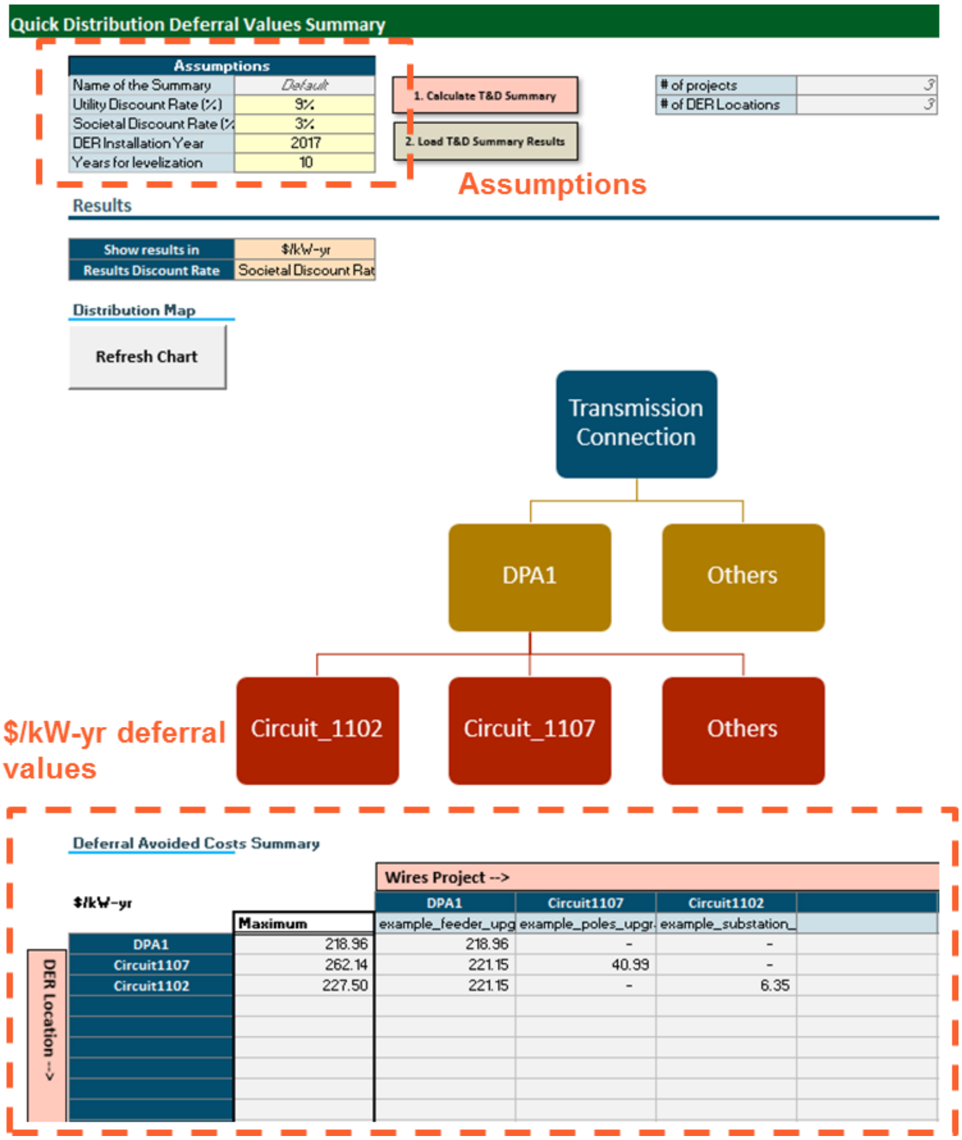
The remaining of this Chapter outlines the case up process in the two screenings.

2.5.1 DISTRIBUTION HOTSPOT SCREENING

The ***DL Screening*** tab in the Distribution Values Screening UI is the place for setting up and running the quick screening summary. As shown in the figure below, after setting up distribution system data through the user interface (instructions in Chapter 2.3.3), the user only needs to specify some basic information (e.g. discount rates) to run the quick summary. Users can press "1. Calculate T&D Summary" and "2. Load T&D Summary Results" to run and load the results. The total model running time should be within a couple of minutes.

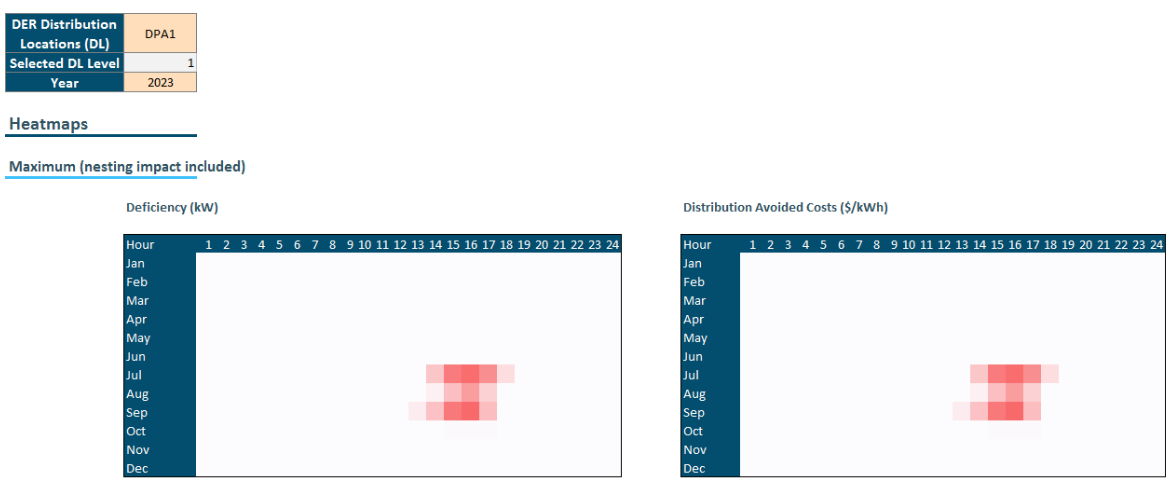
After the results are loaded, users can find the topology of the saved distribution locations in the hierarchy charts and the marginal avoided costs summary table below. In the summary table, the distribution locations where DER can potentially be installed are listed in each row and each column is the potential wires project that can be deferred. For the cell in row X and column Y, it shows the $/kW-yr that can potentially be achieved by DER technologies located at X location for deferring Y project. And the maximum column shows the maximum deferral values for DER at X location after accounting for the nesting impact.

Figure 2-61 Distribution Values Screening UI: Distribution Hot Spot Screening - Case Setup



The ***DL Screening – Heat Maps*** tab shows the heat maps of deficiency (kW) and distribution avoided costs ($/kWh) for the distribution locations that are screened in the "DL Screening" tab. First, the user selects one interested distribution location for DER installation, and after refreshing, this tab shows three sets of the heat maps: 1) for the selected distribution location, 2) for the corresponding upstream distribution locations, and 3) for the previous two combined. The upstream locations are those that will be impacted by DERs installed at the selected location. For example, if the Circuit A is nested within the Feeder 1, then installing PV in the Circuit A will reduce the load in both Circuit A and Feeder 1. This nesting impact can be captured in the tool.

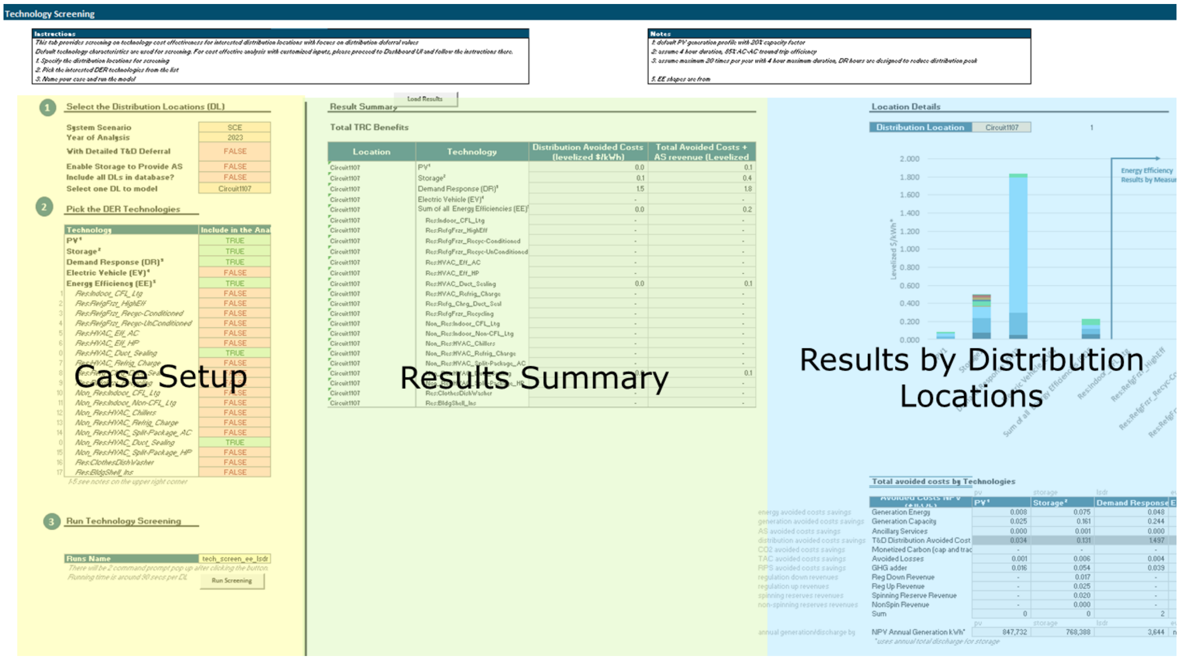
Figure 2-62 Distribution Values Screening UI: Heat Maps for Distribution Locations



2.5.2 TECHNOLOGY SCREENING

The screenshot of the technology screening tab is shown in the Figure 2-63 below. The case setup section is on the left, and to the right there are two results sections. One result section summarizes the average $/kWh distribution avoided costs and total system values for all distribution locations, and the other section lists out the system values by components for a selected distribution location.

Figure 2-63 Distribution Values Screening UI: Technology Screening Overview



To reduce the amount of time that users need to spend on compiling technology parameters, the model assumes default technology characteristics for the technology screening process. The default assumptions are listed below and in the Notes section of the “Technology Screening” tab.

- **PV**: 20% capacity factor PV generation profiles
- **Energy Storage**: 4-hour duration, 85% AC-AC round trip efficiency, 0% parasitic losses, no degradation
- **Demand Response (DR) Program**: maximum calls: 20 times per year; maximum duration: 4 hours; DR hours are decided by the model based on the distribution peak
- **Electric Vehicle (EV)**: battery electric vehicle with 250-mile range with a level 2 charger at home; customer is assumed to charge based on the real time rate that reflects system constraints

- **Energy Efficiencies (EE)**: EE shapes and performance information are based on the Database for Energy Efficient Resources (DEER)

Figure 2-64 is a screenshot for the case setup section. After choosing the system scenario, distribution locations, and the interested DER technologies in steps one and two, users can name the case and start running the model step three. The default system scenarios include the CPUC 2018 Avoided Costs for three IOUs by climate zones, as well as the historical NP-15 and SP-15 Day Ahead (DA) energy and ancillary services prices. More details about the default database are in Chapter 7. If users prefer to set up their own system scenarios, please follow the instructions in Chapter 2.3.2 to save the inputs into a data folder. After the user-defined scenario is saved to the database, users can reopen the "Distribution Values Screening" UI and the new scenario should show up in the dropdown list.

To reduce the amount of time that users need to spend on compiling technology parameters, the model assumes default technology characteristics for the technology screening process. The default assumptions are listed below and in the Notes section of the "Technology Screening" tab.

- **PV**: 20% capacity factor PV generation profiles
- **Energy Storage**: 4-hour duration, 85% AC-AC round trip efficiency, 0% parasitic losses, no degradation
- **Demand Response (DR) Program**: maximum calls: 20 times per year; maximum duration: 4 hours; DR hours are decided by the model based on the distribution peak
- **Electric Vehicle (EV)**: battery electric vehicle with 250-mile range with a level 2 charger at home; customer is assumed to charge based on the real time rate that reflects system constraints
- **Energy Efficiencies (EE)**: EE shapes and performance information are based on the Database for Energy Efficient Resources (DEER)

Figure 2-64 Distribution Values Screening UI: Technology Screening - Case Setup

1 Select the Distribution Locations (DL)

System Scenario	SCE
Year of Analysis	2023
With Detailed T&D Deferral	FALSE
Enable Storage to Provide AS	FALSE
Include all DLs in database?	FALSE
Select one DL to model	Circuit1107

2 Pick the DER Technologies

	Technology	Include in the Analy
	PV[1]	TRUE
	Storage[2]	TRUE
	Demand Response (DR)[3]	TRUE
	Electric Vehicle (EV)[4]	FALSE
	Energy Efficiency (EE)[5]	TRUE
1	*Res:Indoor_CFL_Ltg*	FALSE
2	*Res:RefgFrz_HighEff*	FALSE
3	*Res:RefgFrz_Recyc-Conditioned*	FALSE
4	*Res:RefgFrz_Recyc-UnConditioned*	FALSE
5	*Res:HVAC_Eff_AC*	FALSE
6	*Res:HVAC_Eff_HP*	FALSE
0	*Res:HVAC_Duct_Sealing*	TRUE
7	*Res:HVAC_Refrig_Charge*	FALSE
8	*Res:Refg_Chrg_Duct_Seal*	FALSE
9	*Res:RefgFrz_Recycling*	FALSE
10	*Non_Res:Indoor_CFL_Ltg*	FALSE
11	*Non_Res:Indoor_Non-CFL_Ltg*	FALSE
12	*Non_Res:HVAC_Chillers*	FALSE
13	*Non_Res:HVAC_Refrig_Charge*	FALSE
14	*Non_Res:HVAC_Split-Package_AC*	FALSE
0	*Non_Res:HVAC_Duct_Sealing*	TRUE
15	*Non_Res:HVAC_Split-Package_HP*	FALSE
16	*Res:ClothesDishWasher*	FALSE
17	*Res:BldgShell_Ins*	FALSE

1-5 see notes on the upper right corner

3 Run Technology Screening

Runs Name	tech_screen_ee_lsdr

There will be 2 command prompt pop up after clicking the button.
Running time is around 30 secs per DL

Run Screening

The total model run time depends on the number of distribution locations and technologies selected, the interval of the system scenario timeseries (e.g. 5-min real time prices vs hourly DA prices), as well as your computer system specs. It takes approximately three minutes to run one distribution location for all technologies in the hourly interval for a normal desktop (e.g. 16 GB RAM + Intel i7 3.40 Ghz CPU).

After the model is finished running, users can click “Load Results” button to load in results. Distribution avoided costs and total system values for each technology are summarized in the table for all distribution locations. And the breakdown of each component in system values for one distribution location can be found in the chart and table on the right-hand side.

Figure 2-65 Distribution Values Screening UI: Technology Screening - Results Section

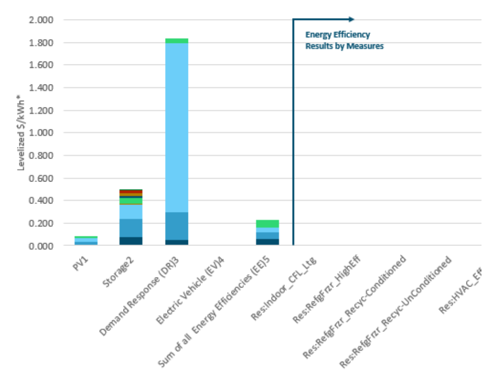
Result Summary Load Results

Total TRC Benefits

Location	Technology	Distribution Avoided Costs (levelized $/kWh)	Total Avoided Costs + AS revenue (Levelized
Circuit1107	PV[1]	0.0	0.1
Circuit1107	Storage[2]	0.1	0.4
Circuit1107	Demand Response (DR)[3]	1.5	1.8
Circuit1107	Electric Vehicle (EV)[4]	-	-
Circuit1107	Sum of all Energy Efficiencies (EE)[5]	0.0	0.2
Circuit1107	Res:Indoor_CFL_Ltg	-	-
Circuit1107	Res:RefgFrzr_HighEff	-	-
Circuit1107	Res:RefgFrzr_Recyc-Conditioned	-	-
Circuit1107	Res:RefgFrzr_Recyc-UnConditioned	-	-
Circuit1107	Res:HVAC_Eff_AC	-	-
Circuit1107	Res:HVAC_Eff_HP	-	-
Circuit1107	Res:HVAC_Duct_Sealing	0.0	0.1
Circuit1107	Res:HVAC_Refrig_Charge	-	-
Circuit1107	Res:Refg_Chrg_Duct_Seal	-	-
Circuit1107	Res:RefgFrzr_Recycling	-	-
Circuit1107	Non_Res:Indoor_CFL_Ltg	-	-
Circuit1107	Non_Res:Indoor_Non-CFL_Ltg	-	-
Circuit1107	Non_Res:HVAC_Chillers	-	-
Circuit1107	Non_Res:HVAC_Refrig_Charge	-	-
Circuit1107	Non_Res:HVAC_Split-Package_AC	-	-
Circuit1107	Non_Res:HVAC_Duct_Sealing	0.0	0.1
Circuit1107	Non_Res:HVAC_Split-Package_HP	-	-
Circuit1107	Res:ClothesDishWasher	-	-
Circuit1107	Res:BldgShell_Ins	-	-

Location Details

Distribution Location | Circuit1107 | 1



Total avoided costs by Technologies

	Avoided Costs NPV ($/kWh)	PV[1] (pv)	Storage[2] (storage)	Demand Response (lsdr)	Electric Vehicle (EV)[4] (ev)
energy avoided costs savings	Generation Energy	0.008	0.075	0.048	-
generation avoided costs savings	Generation Capacity	0.025	0.161	0.244	-
AS avoided costs savings	Ancillary Services	0.000	0.001	0.000	-
distribution avoided costs savings	T&D Distribution Avoided Cost	0.034	0.131	1.497	-
CO2 avoided costs savings	Monetized Carbon (cap and trac	-	-	-	-
TAC avoided costs savings	Avoided Losses	0.001	0.006	0.004	-
RPS avoided costs savings	GHG adder	0.016	0.054	0.039	-
regulation down revenues	Reg Down Revenue	-	0.017	-	-
regulation up revenues	Reg Up Revenue	-	0.025	-	-
spinning reserves revenues	Spinning Reserve Revenue	-	0.020	-	-
non-spinning reserves revenues	NonSpin Revenue	-	0.000	-	-
	Sum	0	0	2	-
annual generation/discharge by	NPV Annual Generation kWh*	847,732	768,388	3,644	nan

*uses annual total discharge for storage

2.5.3 FEATURE LIMITATION

This UI is designed with the focus on quantifying distribution deferral values and can only perform the analysis with a subset of features. If more comprehensive features are needed, users can follow the standard case set up instructions and use the "Model Dashboard UI" and "Inputs Generator UI" for initializing cases and viewing results.

Features that are NOT available in the "Distribution Values Screening UI" are summarized below:

Distribution Hotspot Screening

+ Any DER technology related features; no technology specifications are considered
+ Any other revenue streams

Technology Screening

+ User defined technology characteristics; default technology characteristics are used
+ Customer bill savings analysis and customer reliability values are not included
+ Customized demand response and resource adequacy programs are not included

3 Methodology

The Solar + Storage Tool was developed to evaluate the optimal dispatch of integrated solar and storage systems and estimate the value proposition of these systems based on their expected operations, location on the grid, market prices and other characteristics. The tool evaluates distributed solar with storage and other controllable Distributed Energy Resource (DER) technologies such as smart thermostats, electric vehicle chargers, and other devices, and evaluates optimal dispatch for a wide range of customer programs and incentive designs.

Active technologies are dispatched to maximize value for owners based on the available revenue streams, and cost tests are calculated from different perspectives. Available technologies include energy storage, PV, EV, thermal generator, water heater, and HVAC systems. The interactions among active technologies are captured in the optimization.

This chapter is organized in the following way:

First, benefit categories quantified in the model are discussed and followed by the descriptions for the financing calculation including different financing options and parameters. Then the structure and perspective of each cost test is described. Lastly, the optimization objective function and constraints are discussed.

3.1 Benefits Quantified in the Model

3.1.1 SYSTEM AVOIDED COSTS

System benefits included in the model are based on the avoided costs calculation framework in 2018 Avoided Cost Calculator3 published by California Public Utilities Commission (CPUC). 2018 Avoided Costs are included in the model default dataset, but users can also choose to replace those with their project-specific data.

This section provides a brief overview of the electricity avoided cost components and their contribution to the total electricity avoided costs. The avoided cost used for electricity energy efficiency evaluation is calculated as the sum of six components shown in Table 3-1.

Table 3-1 Components of electricity avoided cost

Component	Description
Generation Energy	Estimate of the hourly wholesale value of energy
Generation Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs associated with expanding transmission and distribution capacity to meet peak loads
Monetized Carbon (cap and trade)	The cost of Cap and Trade allowance permits for carbon dioxide emissions associated with the marginal generating resource

3 HTTP://WWW.CPUC.CA.GOV/GENERAL.ASPX?ID=5267

GHG adder	The difference between the CPUC-adopted total value of CO_2 and the Cap and Trade value of CO_2.
Avoided RPS	This component has been set to zero.

Each of these avoided costs is determined for every hour of the year. The hourly granularity is obtained by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices and actual system loads; Note that the T&D capacity avoided costs are estimated separately for three IOU levels and represents the average avoided costs across each utility's territory. Avoided T&D costs are specific to feeders and can vary dramatically across the territory. Distribution network and potential distribution upgrade information is required at the feeder for a more detailed estimate of T&D avoided costs. If the user is able to access the distribution upgrade information, this model also provides a detailed T&D deferral analysis. More about the methodology on that is described in Appendix A: T&D Deferral Methodology. Table 3-2 summarizes the methodology applied to each component to develop this level of granularity.

Table 3-2 Summary of methodology for electricity avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward market prices and the $/kWh fixed and variable operating costs of a CCGT	Historical hourly day-ahead market price shapes from MRTU OASIS
Generation Capacity	Residual capacity value a new simple-cycle combustion turbine	RECAP model that generates outage probabilities by month/hour and allocates the probabilities within each month/hour based on 2017 weather
Ancillary Services	A percentage of Generation Energy value	Directly linked with energy shape

T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings	Hourly 2017 temperature data by climate zone
Monetized Carbon (cap and trade)	CO_2 cost forecast from revised 2017 IEPR mid-demand forecast, escalated at inflation beyond 2030	Directly linked with energy shape with bounds on the maximum and minimum hourly value
GHG Adder	Difference between total value of CO_2 and monetized carbon cost in the energy market prices	Same as monetized carbon
Avoided RPS	Set to zero to be consistent with GHG adder	NA

3.1.2 CUSTOMER BILL SAVINGS

An important benefit for onsite customers, especially behind-the-meter customers, is bill savings. Energy and demand charge bill savings are calculated simply by comparing the bill before and after the DER technologies. When there are multiple technologies onsite, bill savings are calculated in the "technology loading order". For example, if EE is order 1 and PV is order 2, then EE bill savings is the differences between original bill and bill with only EE impacts. And PV bill savings is equal to bill with only EE impacts minus bill with EE and PV impacts.

3.1.3 UTILITY PROGRAM REVENUES

Utility programs offer another key value stream for onsite customers. The two main program categories are Resource Adequacy (RA) program revenue for FTM customers (or Demand Response (DR) program revenue for BTM customers) and Custom Signal programs.

As discussed in section 2.3.4.2, the net revenue for RA/DR programs can consist of a monthly capacity payment (\$/kW-month), a volumetric payment (\$/kWh), and a penalty (\$/kWh).

Depending on how the RA/DR program is designed, the program may include all or none of these elements.

The capacity payment is made monthly for each kW of capacity in the customers contract size. For the volumetric payment, the customer is compensated for every kWh of energy delivered during a call event. The penalty is applied if the customer fails to deliver their contracted load during a call event. In each timestep, if the load delivered is below the contract commitment then the resulting deficit is converted to an energy value and the penalty is applied across all timesteps of the call event.

For the Custom Signal program customers are compensated for any energy dispatched at the rate defined by the custom signal timeseries. Various combinations of custom signal and DR/RA programs can be combined to provide more revenue options for the customer.

3.1.4 ANCILLARY SERVICES REVENUE

For FTM technologies and future BTM technologies, ancillary services revenues can also be an important revenue stream. Ancillary services modeled are regulation up, regulation down, spinning reserve, and non-spinning reserve.

The model simulates the ancillary services revenue following CAISO's rules on high level. Assumptions are made to simply some details rules and payment calculation. Ancillary services rules implemented in the model are described below:

+ Bids are implemented at the hourly level
+ 15% of the total bid energy are assumed to be consumed/charged for the regulation services. For example, if storage bid 100 kWh for regulation up services for the next hour, and during the hour CAISO sends upward signal between 0 – 100 kW for the storage device

to follow. At the end of the hour, we assume total 15% of the 100 kWh, 15 kWh is discharged to the grid due to the varying signal. The 15% is based on historical CAISO dispatch data

+ Spinning and Non-spinning reserves are for emergency only, thus the model assumes these two services won't be called

3.1.5 T&D DEFERRAL VALUES

The devices might be able to defer some of the substations and feeders upgrade projects if they can reduce distribution system peak. The deferral values which are the time values of deferring upgrade costs to the future are included in the objective function when this revenue stream is included. The deferral values vary in a wide range within utilities' territory which depend heavily on the potential upgrade project and the expected load growth for the distribution area. Model provides two ways to quantify the values. The simple way uses $/kW-year pre-loaded high, medium, and low distribution avoided costs for each IOUs and quantifies the values by multiplying the peak load reduction with $/kW-year avoided costs. The more detailed way sends the price signal to optimization model to dispatch DER devices for peak reduction and analysis the values based on how many years the DER projects are able to deferral upgrade projects for each adjacent distribution area. More descriptions on the detailed T&D deferral are in Appendix A: T&D Deferral Methodology.

3.1.6 RELIABILITY VALUE

During grid outage, reliable distributed generators and batteries including storage, fuel cell generator, and electricity vehicle might be able to support onsite critical load. Model quantifying the reliability values based on the probability of the outage events, the value of lost load, and the technology's capability of providing energy during outage.

+ Grid outage probability

Outage Probability is estimated based on the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Using the Santa Monica City's reliability metrics published by SCE[4] as an example:

Table 3-3 SADI and SAFI figures published by SCE.

	Santa Monica City	
Year	SAIDI (mins)	SAIFI
2016	75.9	1.1
2017	48.9	0.6

$$Average\ Outage\ Probability = \frac{SAIDI \times SAIFI}{8760\ hours \times 60\ mins/hour}$$

+ Value of lost load (VoLL)

The estimates of customer reliability vary widely. Residential customers typically indicate a low willingness to pay to improve reliability and value of service estimates are correspondingly low. On the other hand, commercial value of service is much higher, nevertheless, the demonstrated willingness to pay for reliability is typically much lower than values suggested by surveys. The Interruption Cost Estimate (ICE) Calculator[5] developed by Lawrence Berkeley National Laboratory and Nexant, Inc. can be used as an reference for VoLL

Table 3-4 $/kW VOLL numbers from Interruption Cost Estimate (ICE) Calculator

Customer Class	Cost per Unserved kWh

4 HTTPS://WWW.SCE.COM/NRC/RELIABILITY/REPORTS/SANTAMONICA.PDF
5 HTTPS://ICECALCULATOR.COM/INTERRUPTION-COST

Residential	\$5.82
Small Commercial & Industrial	\$288.71
Medium and Large Commercial & Industrial	\$147.27

+ Technologies' ability to support load

  The model credit different technology differently for supporting load during grid outage events:

  - **Fuel Cell Generators** are assumed to have enough fuel supply onsite and are able to provide the full capacity
  - **Storage** devices' provision are given based on the current SOC during events. **Electric Vehicle** is similar, but the provision only counts when EVs are plugged in

The reliability value is calculated using the following formula:

$$Reliability\,Value\,(\$) = VoLL\left(\frac{\$}{kWh}\right) \times Outage\,Probability \times Covered\,Load\,(kWh)$$

3.2 Financing Calculation

The model also has a built-in pro forma section which calculates the cost for financing the projects based on developers' finance situation and intended financing method. Users can choose to either self-finance the project with a combination of debt and cash or purchase from a third-party through PPA or lease agreement.

If users choose to self-finance, users can specify the debt interest rate, tax rates, and Weighted Average Capital Cost (WACC) for the developer. The model calculates the corresponding debt costs, taxes, and equity investments that are needed for this project.

If third-party PPA/lease option is chosen, the same set of finance parameters are required for the third party. The model calculates the breakeven PPA/lease price that the third-party would charge developers to earn their intended return on equity (ROE). And the calculated PPA/lease price would be the cost for developers.

If there are multiple DER technologies for the same onsite customer, all DER technology is financed together. The finance period is the same as the project lifetime users specified in case configuration. Technology with shorter lifetimes will be replaced until the project lifetime if auto-replacement is chosen in the case setting.

3.2.1 PROJECT COSTS

This section discusses how project costs and financing are calculated in the model. There are five primary cost streams that are utilized in the calculation of project costs for each technology – Capital Costs, Operating Costs, Financing Costs, Tax Costs and Benefits from Incentives.

- Capital Costs
  - Capital costs are calculated separately for each technology in the pro forma. For PV, Fossil generators, HVAC and WH,

    $$Total\ system\ cost\ (\$) = Technology\ capital\ cost\ \left(\frac{\$}{kW}\right) \times Technology\ capacity\ (kW)\ .$$

  - For EV's there is no capital cost, as EV participation is a program cost and does not include cost of capital. Energy storage costs account for both the capacity and duration of a battery

    $$Total\ system\ cost\ (\$) = Battery\ capital\ cost\ \left(\frac{\$}{kW}\right) \times Battery\ capacity\ (kW)\ +\ Battery\ energy\ cost\ \left(\frac{\$}{kWh}\right) \times Battery\ energy\ (kWh)\ .$$

- For load modifiers, the capital cost is calculated by averaging an annual load reduction in kWh which is multiplied by a $/kWh load reduction value. For PV, fossil generators and storage there is also an interconnection cost adder ($/kW) which is multiplied by the nameplate capacity.
- Capital cost is split into equity investment and debt payments according to the debt ratio of each technology. Equity investments are assigned to the year before the technology comes online, while debt payments are annualized and will be covered in the financing costs section.

+ Operating Costs
  - Annual operating costs are calculated by summing variable O&M, fixed O&M and insurance costs for each technology according to the formula: $Operating\ cost\ (\$) = \left[Fixed\ O\&M\ costs\ \left(\frac{\$}{kW}\right) + \ Insurance\ costs\ \left(\frac{\$}{kW}\right)\right] \times Technology\ capacity\ (kW)\ + Variable\ O\&M\ cost\ \left(\frac{\$}{kWh}\right) \times Annual\ energy\ dispatched\ (kWh)$

+ Financing Costs
  - Financing costs are calculated by annualizing debt costs over a debt period using a payment function, which is found in excel or python (NumPy) as PMT. An annual debt service is calculated using the following formula:

    $Debt\ service\ (\$)\ =\ PMT(Debt\ interest\ rate, Debt\ period, Debt\ amount)$
  - The debt service is decomposed into an interest payment, which is the remaining debt amount multiplied by the debt interest rate and a principal payment, which is the difference between the debt service and the interest payment.
  - $Interest\ payment\ =\ Remaining\ debt\ x\ Debt\ interest\ rate$
  - $Remaining\ debt\ =\ Current\ debt\ -\ (Debt\ service\ -\ Interest\ payment)$
  - The differentiation between interest payments and debt payments is an important distinction for tax purposes, which is detailed in the tax calculation section below.

- Incentives
  - Storage systems qualify for the self-generation incentive program (SGIP) as well as the investment tax credit (ITC) if they are paired with a solar system. PV systems also qualify for the ITC.
  - The investment tax credit benefits are calculated by multiplying a user specified "% of total system cost eligible for ITC" by the total system cost of the solar or storage technology. The SGIP incentive is currently calculated by multiplying a user input SGIP benefit in $ / kW by the capacity of the storage system and allocating this benefit evenly over the number of SGIP years specified (defaulted to 5). These incentives are included in both the operational revenues and the tax calculations as detailed below.
  - Due to proposed updates to the storage incentive program by the California Public Utilities Commission (CPUC) to allocate the SGIP incentive based on emissions reduction performance, the SGIP calculation is subject to change in a future version of the tool.
- Tax Costs
  - Tax costs are calculated using the general method, which utilizes an implicit formula relying on operating profit (a function of taxes).

$$Tax\ costs\ = Tax\ rate\ x\ [(Op.profit\ +\ Incentive\ benefits)\ -\ (Depreciation\ +\ Interest\ payments)\ ]$$

  - Operating profit is not included directly in the cost calculation but is included implicitly according to the methodology outlined in section 2.2.2.
  - Depreciation is calculated using the MACRS tables for a given technology $Depreciation(year)\ =\ Capital\ cost\ x\ MACRS\ \%\ (year)$
  - Tax benefits from depreciation, operating costs, and interest expenses are obtained by multiplying each annual cost by the respective tax rate.

$$Tax\ benefits = Tax\ rate\ x\ [Depreciation\ +\ Operating\ Costs\ + Interest\ expenses\ ]$$

$$Taxes\ saved\ /\ paid = Tax\ benefits\ -\ Tax\ costs$$

- Total Costs
  - The five categories of costs are utilized to obtain the following cost streams to obtain an annual subtotal cost.

    $Subtotal\ cost\ =\ Debt\ service\ payment\ +$ *Operating costs + Equity investment + Total taxes saved / (paid) + Incentives*

3.2.2 PROJECT REVENUES

Because operating profits are a part of the tax cost calculation, the pro forma uses an iterative method to calculate revenues, depending on the option that the users financing option (self-financing or third-party lease fee).

- Self-Financing
  - Self-financing revenues come from the assumption that the user owns and operates the portfolio of DER technologies. Under this option, the user can use the cost-test tab (section 2.3.9) to select revenue streams from the optimization such as bill savings, avoided costs or ancillary services, which are summed to obtain total revenues.
- Third-Party Lease Fee
  - Third-party lease fee is the payment that an operator who is leasing a DER portfolio must pay to a third party for the right to operate the fleet of technologies. The third-party lease fee is also displayed as the project cost and can be thought of the cost to operate the group of DER's if the user does not own the devices. The fee is calculated by using the formula:

$$Lease\ Fee\ \left(\frac{\$}{kW}\right)\ = \frac{NPV(cost\ of\ equity,\ \ subtotal\ costs)}{(NPV(cost\ of\ equity,\ \ Nameplate\ kW)\ x\ (1 - effective\ tax\ rate))}$$

- This lease fee is then multiplied by the nameplate kW of the system to obtain an annual lease payment, which is used by the model as an optimization revenue.

Once operating revenues are determined, whether by the lease fee or self-financing method, an after-tax equity cash flow (ATECF) can be calculated.

$ATECF\ (\$) = Op.revenues + Incentives - Op.costs$ – *Equity investment* – *Debt payment costs* – *Tax costs*

3.2.3 TECHNOLOGY CONSOLIDATION

After a set of annual costs and benefits are generated for each technology, the fleet of portfolios are consolidated based on the user input settings for auto replacement and project lifetime.

+ Project lifetime
  - The project lifetime is defined as how long the user is wants to finance the fleet of DER's and is set as either the maximum lifetime of all technologies, minimum lifetime of all technologies, or a numerical value, depending on the user input.
+ Auto replacement & salvage value
  - Because the technology lifetimes may not be equal to the project lifetime, once a technology has reached the end of its lifetime, it is either retired or replaced depending on if the auto replacement toggle is turned on or off, respectively. The costs and revenues calculated for the original lifetime are then either duplicated for the replacement years or set to 0 if the technology is retired. One exception to this rule is the technology capital costs. Replacing a technology can be cheaper than the original capital cost, so the user can specify a replacement cost as a percentage of the original. The auto replacement calculator will extend the parameters calculated for a single technology lifetime until the project lifetime is reached.
  - If the lifetime of the original or replacement technology is longer than the project lifetime, then a salvage value is applied, which captures the value of reselling an asset before the end of its useful life.

$$Salvage\ value\ (\$) = \frac{years\ remaining}{technology\ lifetime}\ x\ capital\ cost\ (\$)$$

+ Financial outputs
    - Once auto replacement and salvage values are complete, there will be a complete set of cost and revenue outputs for each technology in each year of the specified project lifetime.

3.3 CPUC Standard Practice Manual Cost Tests

This subsection presents a brief overview of the CPUC cost-effectiveness tests for demand side programs and how they were applied in the model. Four cost tests that are most commonly used are the Participant Cost Test (PCT), Total Resource Cost Test (TRC), Ratepayer Impact Measure Cost Test (RIM), and Program Administrator Cost Test (PAC). Model also include the Societal Cost Test (SCT) which is similar to TRC but includes externalities and uses a lower discount rate. Table 3-5 shows how the various economic impacts are viewed as costs or benefits from different cost test perspectives. A green cell with a plus sign indicates that the component is considered as a benefit, while a red cell with a minus sign indicates that the component is a cost.

Table 3-5 Costs and Benefits from Each Cost Test Perspective.

Benefit and Cost Component	TRC	RIM	PCT	PAC
Federal Tax Credits	+		+	
SGIP Incentive		-	+	-
Customer Bill Savings		-	+	
Reliability Value	+		+	
Unsubsidized Total System Cost	-		-	
Avoided Generation Energy	+	+		+

Avoided Generation Capacity	+	+		+
Avoided Ancillary Services	+	+		+
Avoided T&D Capacity	+	+		+
Avoided Monetized Carbon (cap and trade)	+	+		+
Avoided GHG Adder	+	+		+

3.3.1 PARTICIPANT COST TEST (PCT)

The PCT is designed to assess if a demand side program is cost effective from the perspective of the end consumer who chooses to participate in a program or install a DER or energy efficiency measure. The costs to the participants are the purchase cost of the DER system. The benefits to the participants are the Federal Investment Tax Credit (ITC) for solar and energy storage systems, the California Self-Generation Incentive Program (SGIP), retail electricity bill savings, and reliability value from the DER system providing an uninterruptible power supply (if applicable).

3.3.2 TOTAL RESOURCE COST TEST (TRC)

The TRC assesses the monetized costs and benefits to California State. The costs are the installed cost of the DER system. The benefits to California are the avoided costs of supplying energy and the ITC. Costs of supplying energy are avoided when load is reduced or shifted from times when resources are expensive or limited to times when they are less expensive. The avoided costs of supplying energy include avoided ancillary services purchases, avoided resistive transmission and distribution losses, avoided emissions compliance costs, avoided generation capacity costs, avoided energy purchase or generation costs.

3.3.3 RATEPAYER IMPACT MEASURE TEST (RIM)

The RIM quantifies the effect of a program on the non-participant ratepayers, comparing the avoided cost savings to the utility to the lost revenue from customer bill reductions. The costs of the RIM are the bill savings from the customers. The benefits of the RIM include all the avoided costs of the TRC. A negative RIM represents a cost-shift that is borne by non-participating ratepayers. SGIP is also included as a cost to the non-participant ratepayers, because the SGIP incentive is funded by the three California Invest Owned Utilities (IOUs). A positive RIM is not required for DER in California; most DER measures have a negative RIM but are nevertheless promoted to achieve broader policy goals. The RIM is provided here as a measure of the benefits to California ratepayers for DER projects and an indication of the viability of the economic and business model for DER projects. A DER business model that imposes large cost-shifts to non-participating ratepayers will not be viable at a large scale until the cost-shift is addressed.

3.3.4 PROGRAM ADMINISTRATOR COST (PAC) TEST

The PAC Test measures the impact of the program based on the costs incurred by the program administrator. On the benefit side, it includes the same avoided costs as the TRC and RIM tests. And on the cost side, it includes incentive costs and excludes any net costs incurred by the participants. The PAC test is very similar to the RIM test, however it represents the increase or decrease in the average customer bills or equivalently the utility revenue requirement instead of the rates for non-participants. As the result, bill reduction from participants doesn't count as the cost in the PAC test. The positive PAC test means the reduction in average customer bills, but it doesn't mean bills are declining for everyone. A measure may be societally not cost-effective and be leading to large cost-shifts yet still reduce the average bill.

3.4 Technology Dispatch Optimization

Active technologies are dispatched to minimize the net costs for the owner subject to technology operating constraints and market constraints. Users select available revenue streams when configuring the cases. This Chapter provides an overview of the optimization model with formulas and explanations.

3.4.1 OBJECTIVE FUNCTION

The objective of the model is to minimize the net costs through operation of the active device(s). The objective function dispatches the active devices to minimize net energy costs or maximize net revenues, accounting for charging costs, operating costs and efficiency losses. In addition, the user can specify certain preferences penalties and a monetary value for additional reliability.

In words, the objective is to **minimize net costs**, where:

$$\begin{aligned} Net\ Costs = \ & Electricity\ Costs + DER\ Operating\ Costs - Additional\ Available\ Revenue \\ & - Reliability\ Value \end{aligned}$$

Each component in the objective function is described in detail in the following section.

This objective is subject to the constraints in the Section 0. Constraints include tracking electricity costs, tracking available revenue streams and physical operating constraints of the technologies.

3.4.1.1 Electricity Costs

Electricity costs reflect the costs to serve customer’s load from a specified perspective. Electricity price varies as the control arrangement and perspective changes. Users can choose from the following three control arrangements based on the location of the site and technology ownership.

- **Customer Control:** in this arrangement, the electricity price is the specified customer retail rate, and the active devices are dispatched to minimize the customer bill.
- **Utility Control:** electricity price is the hourly total utility avoided costs to reflect the costs of generating power from the utility's perspective. The active devices are dispatched to minimize the utility cost of delivering electricity. The components in avoided costs are discussed in Chapter 3.1. To model a front-of-meter storage system participating in wholesale markets, users can also replace the avoided energy cost with the day ahead (DA) energy prices that the project has access to.
- **Utility Control (Contract Days):** a hybrid approach, where technologies are dispatched for customer bill reduction on most days, but on a subset of "contract days," the technologies are controlled to maximize utility benefits

3.4.1.2 Additional Available Revenue

In addition to reducing electricity costs, the technologies can also participate in other markets and programs to gain extra revenues. Model is able to simulate the following revenue streams and users can choose available revenues for the customer when setting up the case. Assumptions about these revenue streams are discussed in Chapter 1.1.3. And more details on the methodology can be found in Chapter 3.1

- Ancillary Services Revenue
- Resource Adequacy Program Revenue
- Generic Utility Program Revenue
- T&D Deferral Value
- Reliability Value

3.4.1.3 DER Operating Costs

Technologies operating cost include the following four components:

O&M Costs

Variable and fixed operating and maintenance costs for technologies

Battery Degradation Costs (Storage and EV only)

Battery degradation costs are calculated based on the cycles, the total lifetime cycles, and the costs of replacing the battery.

Fuel Costs (Thermal Generator Only)

The fuel costs for running the thermal generator

Preference Penalties (EV, Water heater, and HVAC only)

The penalty for deviating from the customer's set point. For example, when customer need to drive but there is not enough energy left in the battery, the penalty is added in the objective function.

3.4.2 CONSTRAINTS

Constraints are included to ensure the technology operations follow the physical and market requirements. Constraints are described below for each technology.

3.4.2.1 Energy Storage Operations

Maximum Power Rating Limit the maximum charge/discharge power to be less than the battery's rated power.	$Power_t^{Charge} = Charge_t^{energy} + Bid_t^{regdown} \leq P^{max}$ $Power_t^{Discharge} = Discharge_t^{energy} + Bid_t^{regup} \leq P^{max}$
Charge/Discharge for Regulation Service Define an energy charge/discharge for providing regulation up/down service.	$Charge_t^{regdown} = MILEAGE^{regdown} \times Bid_t^{regdown}$ $Discharge_t^{regup} = MILEAGE^{regup} \times Bid_t^{regup}$
State of Charge Track the state of charge of the battery based on charge and discharge amount and efficiency losses to ensure battery stays within defined energy range and can provide all AS it bids	$Charge_t = Charge_t^{energy} + Charge_t^{regdown}$ $Discharge_t = Discharge_t^{energy} + Discharge_t^{regup}$ $SoC_t = (1 - PARASITIC) \cdot SoC_{t-1} + (EFF \times Charge_{t-1}) - (Discharge_{t-1}/EFF)$ $SOC^{min} \leq SoC_t \leq SOC^{max}$
Spin and Non-spin Bid Energy Balance the tool assumes spin/non-spin bids are	$Discharge_t^* = Discharge_t^{energy} + Discharge_t^{regup} + Bid_t^{spin} + Bid_t^{nonspin}$ $SoC_t^* = (1 - PARASITIC) \cdot SoC_{t-1}^* + (EFF \times Charge_{t-1}) - (Discharge_{t-1}^*/EFF)$ $SOC^{min} \leq SoC_t^* \leq SOC^{max}$

never called but ensures that battery's state of charge is sufficient to serve any bids	
Spin on and off rule Model constraint storage to only provide spinning reserve for continuous two hours to make sure sufficient energy can be provided when spinning service is called	$Spin\_On_t + Spin\_On_{t+1} \geq Spin\_Start_t \times 2$ $Spin\_On_t + Spin\_On_{t+1} + Spin\_On_{t+2} + Spin\_On_{t+3} \leq 2$ $Spin\_On_t = 1$ *if storage provides spinning reserve in hour t else 0* $Spin\_Start_t = 1$ *if t is the first hour storage starts providing spinning reserve else 0*
Only Charge from Solar (for ITC) To qualify for ITC, only allow storage to be charged from the associated PV. Regulation down is also disabled.	$Bid_t^{regdown} = 0$ $Power_t^{Charge} \leq PV_t$

3.4.2.2 Distributed Thermal Generator

The distributed thermal generator can be used to model any type of dispatchable generator that takes a fuel (e.g., a diesel generator or fuel cell). The generator will be economically dispatched subject to operating constraints such as ramp rate and unit commitment. O&M costs will be calculated based on a single-value average heat rate.

Maximum Power Rating Limit the maximum energy and AS provision by the distributed thermal generator by its (maintenance-derated) power rating.	$Power_t^{energy} + Bid_t^{regup} + Bid_t^{spin} + Bid_t^{nonspin} \leq DERATE^{maint} \cdot P^{max} \cdot Commit_t$
Minimum Stable Level Thermal generators must stay above a specified minimum dispatch level if committed.	$Power_t^{energy} - Bid_t^{regdown} \geq DERATE^{maint} \cdot P^{min} \cdot Commit_t$
Dispatch for Regulation Service Define an energy charge/discharge for providing regulation up/down service.	$Dispatch_t^{regdown} = MILEAGE^{regdown} \times Bid_t^{regdown}$ $Dispatch_t^{regup} = MILEAGE^{regup} \times Bid_t^{regup}$
Unit Commitment Ensure unit is committed in line with defined minimum up/down times and associated start/stop costs	$Start_t \geq Commit_t - Commit_{t-1}$ $Stop_t \geq Commit_{t-1} - Commit_t$ $Start_t + \sum_{t=t+1}^{t+uptime} Stop_t \leq 1$ $Stop_t + \sum_{t=t+1}^{t+downtime} Start_t \leq 1$
Ramping Constraints Ensure thermal generators stays within ramping limits	$Power_t^{energy} - Power_{t-1}^{energy} + Bid_t^{regup} + Bid_t^{spin} + Bid_t^{nonspin} \leq RAMP \cdot DERATE^{maint} \cdot P^{max}$ $Power_{t-1}^{energy} - Power_t^{energy} + Bid_t^{regdown} \leq RAMP \cdot DERATE^{maint} \cdot P^{max}$

3.4.2.3 Managed Electric Vehicle Charging

Managed EV charging compares the value of being able to schedule EV charging dynamically based on system need (if under utility control) or customer's rates (if customer control).

Maximum Power Rating Limit the maximum charge/discharge power to be less than the EV battery's rated power.	$Power_t^{Charge} = Charge_t^{energy} + Bid_t^{regdown} \leq P^{max} \times ChargeAvailability_t$ $Power_t^{Discharge} = Discharge_t^{energy} + Bid_t^{regup} + Bid_t^{spin} + Bid_t^{nonspin} \leq P^{max} \times ChargeAvailability_t$
Charge/Discharge for Regulation Service Define an energy charge/discharge for providing regulation up/down service.	$Charge_t^{regdown} = MILEAGE^{regdown} \times Bid_t^{regdown}$ $Discharge_t^{regup} = MILEAGE^{regup} \times Bid_t^{regup}$
State of Charge Track the state of charge of the EV battery based on driving needs, charge and discharge amount, and efficiency losses to ensure battery stays within defined energy range and can provide all AS it bids	$Charge_t = Charge_t^{energy} + Charge_t^{regdown}$ $Discharge_t = Discharge_t^{energy} + Discharge_t^{regup}$ $SoC_t = (1 - PARASITIC) \cdot SoC_{t-1} + (EFF \times Charge_{t-1}) - \left(\frac{Discharge_{t-1}}{EFF}\right) - DRIVING_t$ $SOC^{min} \leq SoC_t \leq SOC^{max}$
Spin and Non-spin Bid Energy Balance The tool assumes spin/non-spin bids are never called but ensures that battery's state of charge is sufficient to serve any bids	$Discharge_t^* = Discharge_t^{energy} + Discharge_t^{regup} + Bid_t^{spin} + Bid_t^{nonspin}$ $SoC_t^* = (1 - PARASITIC) \cdot SoC_{t-1}^* + (EFF \times Charge_{t-1}) - \left(\frac{Discharge_{t-1}^*}{EFF}\right) - DRIVING_t$ $SOC^{min} \leq SoC_t^* \leq SOC^{max}$

EV Driving Need Shortage Penalty Define the probability of not meeting the potential additional driving need that is not included in the specified driving schedule. The shortage penalty is included in the objective function to incentive EV to stay relatively full. a and b are parameters derived from the previous EV study. $\left(a \times \frac{SoC_t}{SOC^{max}} + b\right)$represents the probability of not having enough energy for a trip given the current SOC	$ShortageProb_t = \left(a \times \frac{SoC_t}{SOC^{max}} + b\right) \times AddDrivingProb_t \times ChargingAvail_t$ $Objective\ Function += ShortageProb_t \times Customer\ Preference\ Penalty$
VG1 Constraint If the vehicle is only allowed to charge from the grid, this constraint is implemented	$Discharge_t \leq 0$

To calculate the value of managed charging, the optimal dispatch that is determined by the model is compared against a baseline EV charging input shape.

3.4.2.4 Smart Water Heater

Similar to the managed EV charging, the smart water heater's dispatch is compared to a baseline water heater usage input shape. The user must ensure that the baseline shape used to compare matches the smart water heater technology being dispatched.

Water Heater Heat Losses Define heater losses based on the water and indoor temperature differences and water tank losses parameter	$WaterTankTemp_t(F) = ColdWaterTemp\ (F) + \frac{SoC_t\ (BTU)}{lbH2OPerGal \times WaterTankCapacity(gal)}$ $Losses_t(BTU) = (WaterTankTemp_t - IndoorTemp) \times TankLosses(BTU/F)$
Water Heater Usage in BTU Calculate water heater usage in BTU based on the water usage in Gallon and the water temperature	$WaterUse_t(BTU) = WaterUse_t(Gal) \times (CustomerSetPoint - ColdWaterTemp) \times lbH2OPerGal$
Water Heater Heating Element Heat Gain Define the heat gain from using heating element at each timestep	$HEHeatGain_t(BTU) = HEPower_t\ (kW) \times HECOP \times BtuPerkWh$
Water Heater Heat Pump Heat Gain Define the heat gain from using heat pump at each timestep	$HPHeatGain_t(BTU) = HPPower_t\ (kW) \times HPCOP \times BtuPerkWh$

Water Heater Energy Balance The energy flows in BTU at each time step	$SoC_{t+1}\ (BTU) = SoC_t\ (BTU) + HEHeatGain_t(BTU) + HPHeatGain_t(BTU) - WaterUse_t(BTU) - Losses_t(BTU)$
Maximum Power	$HEPower_t\ (kW) \leq HEPmax$ $HPPower_t\ (kW) \leq HPPmax$ $HEPower_t\ (kW) + HPPower_t\ (kW) \leq TotalWaterHeaterPmax$
Water Heater Usage Shortage Penalty Similar feature as the shortage penalty for EV: add in a penalty for not meeting the additional water usage need that is not included in the scheduled water usage. This penalty incentive water heater to stay relatively full. a and b are parameters derived from empirical studies: $\left(a \times \frac{SoC_t}{SOC^{max}} + b\right)$represents the probability of not having enough energy for a trip given the current SOC	$ShortageProb_t = \left(a \times \frac{SoC_t}{SOC^{max}} + b\right) \times AddDrivingProb_t \times ChargingAvail_t$ $Objective\ Function += ShortageProb_t \times Customer\ Preference\ Penalty$

3.4.2.5 Smart HVAC

Similar to the managed EV charging and smart water heater, the smart HVAC dispatch is compared to a baseline HVAC usage input shape. The HVAC model assumes that the setpoint temperature is always close enough to the actual hourly interior temperature to simplify and linearize the constraint definitions.

HVAC Mode For a given optimization window (e.g., daily or monthly), assume that the HVAC system is in either heating or cooling mode. This prevents the model from switching between heating and cooling in an unrealistic way.	$AC_t(kW) \leq POWER_{AC}^{MAX}(kW) \times (1 - HeatingMode)$ $Heat_t(kW) \leq POWER_{Heat}^{MAX}(kW) \times HeatingMode$
Max Heating/Cooling	$AC_t(Btu) = SEER \times AC_t(kW)$ $Heat_t(Btu) = SEER \times Heat_t(kW)$
Fan Temperature Impact The fan will either add or remove heat to the interior depending on the exterior temperature. To keep the model linear, we assume that the interior temperature stays close to the setpoint temperature.	$Fan_t(Btu) = \left(TEMP_t^{ext} - TEMP^{setpoint}\right) \times FLOWRATE \times C^{air} \times Fan_t(kW)$ C^{air} the specific heat of air

Ambient Temperature Gain The building will experience temperature gain through conduction, sensible and latent heat gain, as well as solar heat gain. These input values are calculated based on customer building and weather inputs.	$\Delta TEMPGAIN_t(F) = \frac{(CONDUCTION_t(Btu)+SENSIBLE(Btu)+LATENT_t(Btu)+SOLAR_t(Btu))}{THERMAL\ MASS}$
HVAC Temperature Impact The HVAC system can change interior temperature by using a combination of heating, AC, and fans, which contribute changes in heat (Btu) to the interior as a linear function of the thermal mass of the building.	$\Delta Temp_t^{HVAC}(F) = \frac{Heat_t(Btu)-AC_t(Btu)+Fan_t(Btu)}{THERMAL\_MASS}$
HVAC Temperature Balance	$Temp_t^{interior}(F) = Temp_{t-1}^{interior}(F) + \Delta TEMPGAIN_t(F) + \Delta Temp_t^{HVAC}(F)$

3.4.3 ADDITIONAL FEATURES

In additional to reducing electricity costs, the model also simulates other programs and revenue streams for the technologies. This chapter describes the assumptions for those programs.

3.4.3.1 Ancillary Service Markets

The model simulates four CAISO ancillary services markets: Regulation up and down, Spinning reserve, and Non-spinning reserve. The following assumptions based on the historical CAISO market data:

Energy Impact

We assume the energy charge or discharge required for regulation up or down services would be 15% of the bid capacity (e.g. energy mileage of 15%). These values are derived from historical CAISO market transaction record.

- For example, 1MWh reg up bid results in an expected 0.15 MWh decreases in the state of charge

Market Rules

- To bid in the market, the battery needs to have enough charge/discharge capability (kW) and enough energy/headroom (kWh) to deliver the full quantity bid
- There are 4 hours minimum requirement for providing spinning reserve

3.4.3.2 Utility Programs

Resource Adequacy Program

Resource adequacy program pays participants monthly fees and can call them to provide energy during system peak hours and emergencies. But if the participant doesn't respond to the call, they are obligated to pay a penalty. When the resource adequacy program is available, the model chooses whether to participate depending on the penalties for not responding and opportunity costs for participation, including the increased electricity costs, degradation costs, fuel costs, and missing revenues from participating in other revenue streams.

The model assumes the battery operator has perfect information about the timing of calls. And the battery which delivers capacity during calls can also provide other services the rest of the time

Custom Signal Program

A generic "custom signal" utility program is included in the model to provide flexible future program designs. User inputs the hourly price signal for each year, and the customer get extra revenues if they reduce their electricity usage during the hours when the price is positive.

3.4.3.3 Detailed Load Modifiers

With the Detailed Load Modifier feature enabled, the model will not read in the aggregate customer load modifier shape. Instead, the model will go through the following steps to calculate the value of a portfolio of selected EE measures:

1. Read in databases of load modifier unitized electricity and fuel impact shapes
2. Scale the unitized impact shapes by the annual energy and fuel savings per unit defined for the customer's detailed EE selection
3. Net off all detailed EE electricity savings from the customer's load shape before dispatch optimization
4. In results processing, each detailed EE measure's value is calculated separately

a. For New/Replace-On-Burnout measures, benefits are calculated based on the total energy savings relative to a code-standard measure

b. For retrofit measures, the dual baseline treatment means that the measure will get a larger quantified benefit during the years of Remaining Useful Life (RUL) of the existing measure that it replaced. After the RUL has expired, the EE measure will only get benefits relative to the code-standard measure

3.4.3.4 Transmission and Distribution Project Deferral

The Detailed T&D Project Deferral feature allows users to calculate the impact of DERs located at a specific location in the distribution network on all other areas of the network. For example, impacts from DERs installed on a distribution circuit may have upstream impacts at the substation, allowing the DERs to avoid capital projects at both locations. In this way, there may be stacked value for DER installations that are not captured when modeling single locations on the network.

There are two methods for calculating the deferral:

+ **Allocation-Based Average:** Attributed deferral value calculated in this method is based on expected reductions and is not limited to discrete integer years of deferral. Users input the number of years they would like to defer the projects, and the deferral values are calculated based on the target deferral years. Attributed deferral values for the DER device is proportional to the ratio of DER peak reduction to kW reduction needed
+ **Requirement-Based Threshold:** For the project where the DER is installed, the attributed deferral values equals the potential deferral years if the kW reduction is sufficient for deferral, otherwise zero.

Additionally, there are two methods for calculating the peak reduction achieved by the DERs:

- **Peak Capacity Allocation Factor (PCAF):** Peak load hours are defined as the hours where network loads are within one standard deviation of the highest network load. The peak deferral achieved is calculated based on the distribution of DER impacts over these peak hours, accounting for some uncertainty in the peak hour and impact shape of the DER.
- **Coincident Peak:** Peak deferral achieved is calculated based on the single-hour coincident peak impact of each DER.

For more on the T&D project deferral methodology, see Section 5.

3.4.3.5 Detailed Interconnection Costing

By default, customers may need to pay for an interconnection fee to install rooftop PV to compensate for possible exports to the grid that the distribution system was not originally designed to handle. This is a predetermined input value into the Solar + Storage Tool that does not directly affect the DER dispatch.

However, for a more detailed look, the Solar + Storage Tool includes functionality to investigate whether customers can use DERs to reduce their exports to the grid below a certain threshold to avoid triggering a distribution system upgrade that would incur a large interconnection cost that the customer would have to pay. In conjunction with the "**Allow PV to Be Curtailable**" feature toggle, users can investigate how having controllable PV affects the economics of installing DGPV.

With the "**Detailed Interconnection Cost**" feature enabled, the model will use integer decision variables to determine whether exports to the grid exceed the designated thresholds for the affected distribution locations in the network. If the threshold at a specific distribution location is exceeded, the associated interconnection cost is added to the total costs that the dispatch is trying to minimize.

Additionally, enabling the "**Detailed T&D Project Deferral**" feature allows users to investigate how grid exports from PV affect multiple potential distribution upgrades at locations across the distribution network.

3.4.3.6 Solar + Storage Sizing

Storage and PV can be sized optimally to maximize net values given the costs information, customer load shapes, and the potential revenue streams. When this feature is enabled, the battery's power and energy capacities become decision variables and the capital costs of the devices are added into the objective function.

3.4.3.7 Allow DGPV to Be Curtailed

Under normal model operations, the customer's DGPV is assumed to be must-take, so that all energy in the DGPV shape must be used to meet the customer's load or exported to the grid.

This feature toggle is most often used with the "**Detailed Interconnection Costing**" feature to economically avoid grid exports. Additionally, users may want to use this feature if they want to model customers who will economically curtail their local DGPV if they are exposed to negative prices.

3.4.3.8 Fast Optimization

Instead of running the model for the entire year, the user can choose to only run a subset of representative days for a shorter solving time. The full year optimization takes around 60 seconds for one customer, while the fast model takes around 15 seconds.

For each month, 6 representative days are selected. They are the maximum demand day, maximum energy day, and an average day for weekdays and weekends in the month. Total benefits are then calculated based on the dispatch results on the representative days.

The faster optimization model provides results that are within 5% of the optimal results for customers with utility rates. But it might be less accurate for dynamic rates that large time-of-use spikes.

4 Installation Instructions

The tool is written in Python 3, and to simplify the installation process for users, all the required packages and solvers are compiled together as executables. The model is executed through executables stored in the model folder. It checks the system environment and installs the required Python packages if needed. No additional installations are needed.

The following is the system environment that the tool is tested under. The tool might not be compatible under other environments.

- 64-bit Windows 10
- Microsoft Excel version 2016

5 Appendix A: T&D Deferral Methodology

5.1 Overview

DER can either positively or negatively impact the cost of local T&D capacity due to its location on the distribution grid. In general, DER provides benefits by reducing the demands on the T&D system at times of peak demand, thereby allowing the deferral or avoidance of T&D capacity additions. In some cases where there are high amounts of uncontrolled distributed generation on the local system, additional DER could exacerbate the reverse flow problems in the area and trigger or accelerate the need for capacity or protection additions to accommodate the reverse flow. While the methodology discussion presented herein focuses on the deferral case, the methodology is equally applicable to the acceleration case.

The following sections talk about first how the deferral values are calculated given the deferral years in general. Then go into the details of attributing deferral values to each DER system in section 5.3 and the impact shapes and dependable peak load reduction determination for DER systems in section 5.4

5.2 Deferral Values

The deferral values of the DER are the costs differences in the net present value of the T&D capacity project before and after the DER installation. The project costs include both project upgrade capital costs and ongoing O&M costs, as well as impacts on losses. Optionally, impacts from changes in reliability levels can also be captured in the deferral value.

$$DefValTotPot[a] = DefValCal[a] + DefValOM[a] - DefCostTransLosses[a] - DefCostDistLosses[a] - DefCostAvoidedOutage[a]$$

5.2.1 DEFERRAL VALUE OF CAPITAL PROJECT

$DefValCal[a]$ is the present value of capital deferral savings at the DER installation year y. The savings are for all projects (p) that are affected by DER installed in area (a).

$$DefValCal[a] = \sum_{p \in P} DefValCap[p, a]$$

Where:

p is each project distribution location a

To calculate the deferral value for a single project deferred by DER in location “a” ($DefValCap[p, a]$), capital costs of the project is first converted to revenue requirement costs based on the revenue requirement multiplier. The revenue requirement adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs. Levelized revenue requirement costs in real term are then calculated based on the Real Economic Carrying Cost (RECC). Finally, deferral values are calculated based on the number of years deferred and the levelized revenue requirement costs.

$$DefValCal[p, a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{RECC[p] \times RRC_y[p]}{(1+disc_{real}[inv])^{yr-1+OriUpgradeYr[p]-DERinstalledYr}}$$

$$RRC_y[p] = Capital_{costyr}[p] \times RRMultiplier[inv] \times Einf[inv]^{y-costyr}$$

$$RECC[p] = \frac{disc - Einf[inv]}{1 + disc} \times \frac{(1 + disc)^{blife[p]}}{(1 + disc)^{blife[p]} - (1 + Einf[inv])^{blife[p]}}$$

$$disc_{real} = \frac{1 + disc}{1 + Einf[inv]} - 1$$

Where:

$DefValCal[p, a] =$ NPV of the deferral values in DER installation year

inv = the investment equipment type for the project

$Capital_{costyr}[p]$ = The capital investment in the cost year specified by users for project p

$RRMultiplier[inv]$ = Revenue requirement multiplier that adjusts the engineering cost estimate for the capital project to total revenue requirement cost levels for the types of investment. The adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs.

$Einf[inv]$ (%/yr) = the equipment inflation rate

$RRC_y[p]$ = revenue requirement costs in DER installation year y for the project p

$RECC[p]$ = Real economic carrying charge for the project p. RECC converts capital cost into an annual investment cost savings resulting from a discrete period of deferral.

$disc$ = nominal discount rate

$blife[p]$ = book life of the upgrade project p

$disc_{real}$ = discount rate net of project inflation (%/yr)

$OriUpgradeYr[p]$ = original upgrade year for the project p

$deferral\ years[p,a]$ = number of years that the project (p) can be deferred due to DER installed in the location a = deferred upgrade year – original upgrade year

5.2.2 DEFERRAL VALUE OF AVOIDED INCREMENTAL O&M

In addition to deferral capital investment, the deferred O&M costs also contribute to total deferral values.

$DefValOM[a]$ is the net present value of the O&M deferral saving. The saving is for all projects (p) that are affected by DER installed in area (a). $DefValOM[a] = \sum_{p \in P} DefValOM[p,a]$

$DefValOM[p,a] = \sum_{yr=1}^{deferral\ years[p,a]+1} Capital_{costyr}[p] \times Einf[inv]^{y-costyr} \times OMFctr[inv] \times \left(\frac{1+OMesc[inv]}{1+disc}\right)^{yr-1+OriUpgradeYr[p]-\ DERinstalledYr}$

Where:

$DefValOM[p,a]$ is the NPV of deferred O&M cost at the DER installation year

$OMFctr[inv]$ = O&M Factor for the investment type, O&M factor is the ratio of annual O&M\$/project capital cost \$

$OMesc[inv]$ = O&M escalation rate for the investment type

5.2.3 DEFERRAL COST OF AVOIDED TRANSMISSION LOSSES

$DefCostTransLosses[a] = \sum_{p \in P} DefCostTransLosses[p,a]$

$$DefCostTransLosses[p,a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{AvoidedTransLosses[p, yr + OriUpgradeYear]}{(1 + dist[inv])^{yr-1+OriUpgradeYr[p]-\ DERinstalledYr}}$$

$$AvoidedTransLosses[p,y] = AreaMWh[p,y] \times WeightedEnergyAC[y] \times$$

$$\Delta\mathrm{LossMWh\%[p]} + \mathrm{AreaMW[p,y]} \times \mathrm{AGCC[y]} \times 1000 \times \Delta\mathrm{LossMW\%}[p]$$

Where

$$WeightedEnergyAC[y] = \frac{\sum_{t \in T} EnergyAC[t,y] \times SystemLoad[t,y]}{\sum_{t \in T} SystemLoad[t,y]}$$

T is the set of timesteps in the year y

$AvoidedTransLosses[p,y]$ is the nominal avoided costs ($) for transmission losses at year y after the project p upgrade

$AreaMWh[p,y]$ is energy consumption in the transmission area affected by the project p upgrade

$EnergyAC[t,y]$ is the energy avoided cost at the timestep t

$\Delta LossMWh\%[p]$ is baseline area average annual loss factor minus average loss factor after the project p is completed.

$AreaMW[p,y]$ is the peak MW for the affected area

$AGCC[y]$ is the avoided generation capacity cost in $/kW

$\Delta LossMW\%[p]$ is baseline area peak loss factor minus peak loss factor after the project p is completed

$SystemLoad[t, y]$ is the system load at the timestep t

5.2.4 DEFERRAL COST OF AVOIDED DISTRIBUTION LOSSES

$DefCostDistLosses[a] = \sum_{p \in P} DefCostDistLosses[p, a]$

$DefCostDistLosses[p, a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{AvoidedDistLosses[p,y]}{(1+dist[inv])^{yr-1+OriUpgradeYr[p]-DERinstalledYr}}$

$AvoidedDistLosses[p, y] = AreaMWh[p, y] \times WeightedEnergyAC[y] \times$

$\Delta LossMWh\%[p] + AreaMW[p, y] \times (AGCC[y] + ADC[a, y]) \times 1000 \times \Delta LossMW\%[p]$

Where

$DefCostDistLosses[p, a]$ is the NPV deferral values at the DER installation year

$WeightedEnergyAC[y] = \frac{\sum_{t \in T} EnergyAC[t,y] \times DistLoad[t,y]}{\sum_{t \in T} DistLoad[t,y]}$

T is the set of timesteps in the year y

$AvoidedDistLosses[p, y]$ is the nominal avoided costs ($) for distribution losses at year y after the project p upgrade

$AreaMWh[p, y]$ is energy consumption in the distribution area affected by the project p upgrade

$EnergyAC[t,y]$ is the energy avoided cost at time step t on year y

$\Delta LossMWh\%[p]$ is baseline area average annual loss factor minus average loss factor after the project p is completed.

$AreaMW[p,y]$ is the peak MW for the affected area

$AGCC[y]$ is the avoided generation capacity cost in $/kW

$ADC[a,y]$ is the avoided distribution cost in $/kW for location a

$\Delta LossMW\%[p]$ is baseline area peak loss factor minus peak loss factor after the project p is completed

$SystemLoad[t,y]$ is the distribution load at the timestep t

5.2.5 DEFERRAL COST OF NET AVOIDED OUTAGE

Outage costs are treated in two ways in the model. There are reduced outage costs associated with the T&D investments. Those outage savings are treated as disbenefits and treated the same as distribution capacity values, including adjusting kW impacts for flow factors.

There are also increased reliability benefits provided to customers that install specific types of DG and storage devices. Those impacts are treated as additional benefits for those measures.

These costs do not have direct monetary impacts on utility revenue requirements. They are included in the societal cost tests, and are optional for inclusion in the TRC test.

5.3 Attributed Deferral Value

The model will be designed to have the flexibilities to attribute deferral values using the following two methods:

1) Requirement-based threshold method that attributes the deferral values in a lumpy way: the deferral values are credited to the DER system only when the deferral achieved with the peak load reduction being larger than the kW needed, and the deferral is counted in integer years only. This method is useful to evaluate aggregated DER portfolios because it gives realistic deferral results when all potential DER systems are considered. But if we have no information about other DER systems in the upgrade location and would like to only evaluate a single device, method 2) is recommended.

2) Allocation-based average method: Attributed deferral value calculated in this method is based on expected reductions and is not limited to discrete integer years of deferral. Using this method assumes each DER device contributes to the deferral linearly. Even though a single DER device can't realize the deferral, but it still deserves the deferral credits because it brings the distribution location closer to the deferral threshold.

5.3.1 REQUIREMENT-BASED THRESHOLD

For the project where the DER is installed, the attributed deferral values equal the potential deferral years if the kW reduction is sufficient for deferral, otherwise zero.

For affected projects located in upstream areas, the value is the potential deferral value multiplied by the ratio of the dependable DER reduction divided by the kW needed. Note that the requirement for attaining at least a full year of deferral to attribute value is relaxed for upstream projects. This is done because DER activities in other locations could also affect the upstream projects.

The potential deferral value and the kW needed are calculated based on the target deferral years specified by the user. Any project can be manually excluded if needed.

$AllocVal[a] = \sum_{p' \in P'} DefValTotPot[p', a] + \sum_{p^* \in P^*} DefValTotPot[p^*, a] \times \frac{PeakReduction[p^*,a]}{kWNeeded[p^*]}$

Where:

P' is the set of affected projects that are located at “a”

P^* is the set of upstream projects that are affected by the DER located at “a”

$DefValTotPot[p', a]$ is the deferral value for the project located at “a”. The deferral years used in this calculation is the years that DER can defer by reducing peak load below the upgrade threshold

$DefValTotPot[p^*, a]$ is the deferral value for the upstream projects and are calculated based on the target deferral years

$PeakReduction[p^*, a]$ is the peak reduction for project p^* by DER at location “a”

$kWNeeded[p^*]$ is the kW reduction needed to achieve the target deferral years for project p^*

When there are multiple DER devices at the same location, the deferral values for all DER devices aggregated are calculated first using the previous formulas, so that the overall impacts on deferral are evaluated. Then the values are attributed to individual DER devices based on the ratio of peak load reduction contribution in the portfolio.

5.3.2 ALLOCATION-BASED AVERAGE

Attributed deferral value calculated in this method is based on expected reductions and is not limited to discrete integer years of deferral. Users input the number of years they would like to defer the projects, and the deferral values ($DefValTotPot[p,a]$) are calculated based on the target deferral years. Attributed deferral values ($AllocVal[p,a]$) for the DER device is proportional to the ratio of DER peak reduction to kW reduction needed:

$$AllocVal[a] = \sum_{p \in P} AllocVal[p,a]$$

$$AllocVal[p,a] = DefValTotPot[p,a] \times \frac{PeakReduction[p,a]}{kWNeeded[p]}$$

Where:

P is the set of projects that are affected by the DER located at "a"

$PeakReduction[p,a]$ is the peak load reduction for project "p" at the year of target deferral year by the DER at location "a"

5.4 Dependable Peak Load Reduction

The amount of dependable peak load reduction provided by the DER device differs by the DER locations, the DER output timing, and its flexibilities. This chapter illustrative how the model calculates the DER load reduction contribution from different types of DER systems installed at different locations.

5.4.1 T&D TOPOLOGY

DER systems located at location A might have impacts on multiple capacity projects located electrically upstream from location A. As with the LNBA spreadsheet tool, we use flow factors and location-specific loss factors to identify the impacts of DER systems to the surrounding potential upgrade projects.

5.4.1.1 Flow factors

Flow factors represent the impact % of the DER project to the T&D upgrade project located in the upstream locations.

For example, in the following table for the DER systems installed in DPA2, 100% of its load reduction affects the T&D upgrade in DPA2. And only 90% and 50% of its load reduction would affect the T&D upgrade projects in DPA 1 and DPA3.

DER installation location (a) -->

<--Affected T&D project (p)

flow factors	DPA1	DPA2	DPA3
DPA1	1	0.9	0.8
DPA2	0.8	1	0.5
DPA3	0.8	0.5	1

5.4.1.2 Loss factors

Loss factors indicate the transmission and distribution losses between DER installation location and the potential T&D upgrade location. 10% losses are entered as 1.10 loss factor.

DER installation location (a) -->

<--Affected T&D project (p)

loss factors	DPA1	DPA2	DPA3
DPA1	1.1	1.12	1.15
DPA2	1.12	1.05	1.1
DPA3	1.15	1.1	1.05

The load impact on T&D upgrade project “p’ by the DER systems at the location “a’ would be:

$$LoadReduction[p,a,t] = \frac{LoadReduction[a,t] \times FF[p,a]}{LF[p,a]}$$

5.4.2 IMPACT SHAPES

5.4.2.1 Non-dispatchable technology

We use the fixed impact shapes for non-dispatchable technology which includes PV and Energy Efficiency measures. DER installed in a different location can have different impact shapes based on the PV availabilities and building types.

5.4.2.2 Dispatchable technology

Dispatchable technologies, like energy storage, electric vehicles, smart water heater, and smart HVAC systems, can be dispatched to minimize the peak load at potential T&D upgrade locations. To simulate the optimal load reduction by the dispatchable technologies, a mixed integer linear optimization model is used.

The objective function is to minimize the total costs for the hosting site, which can include demand charges, energy charges, technology O&M costs, battery degradation costs, etc. depending on the type of customers and the location of the hosting site. To simulate the technology dispatches when there are T&D upgrade projects to defer, the deferral values are added into the objective function as a benefit stream. Deferral values for all affected T&D upgrade project are considered in the objective function so that the model can prioritize the dispatchable technologies for high value projects.

Objective function:

Minimize

$$Total\ costs = Other\ net\ costs - T\&D\ deferral\ values[a]$$

Where:

$$T\&D\ deferral\ values[a] = \sum_{p \in P} PeakLoadReduction[p, a] \times ProjectDeferralValue\$perkW[p]$$

Subject to:

$PeakLoadReduction[p,a] \leq Peak[p] - Peak\_after\_DER[p,a]$ for each $p \in P$

$Peak\_after\_DER[p,a] \geq Load[p,t] - \frac{DERNetDischarge[a,t] \times FF[p,a]}{LF[p,a]}$ for each $t \in T$ and $p \in P$

and other market and technology constraints

Where

P is the set of affected T&D upgrade projects

T is the set of timesteps in a year

$DERNetDischarge[a,t]$ is the aggregated DER net discharge at time t at location “a”

$FF[p,a]$ is the flow factors from the DER location a to the T&D upgrade location p

$LF[p,a]$ is the loss factors from the DER location a to the T&D upgrade location p

$ProjectDeferralValue\$perkW[p]$ is the project deferral values calculated by the allocation-based average method for the potential upgrade project p

The details about objective function and other constraints will be covered in a separate document.

The user can choose to only model the dispatchable technologies impact shapes for a year and assume the dispatches stay the same for its life time. This method is suitable for the distribution location whose load shapes are expected to only have minor changes. The other option is to tailor the DER dispatches every year to the forecast future load. Using this method maximizes the distribution peak reduction for each future year and provides higher load reduction. This is especially true when the distribution peaks are expected to shift due to new utility scaled renewables in the future.

5.4.3 DEPENDABLE PEAK LOAD REDUCTION

Given the impact shapes, peak load reduction can be calculated using the following two methods.

5.4.3.1 Coincident peak load reduction

This method accounts the differences between the annual peak before and after DER installations as the dependable peak load reduction. This method doesn't discount load reduction contribution by load and DER output uncertainties.

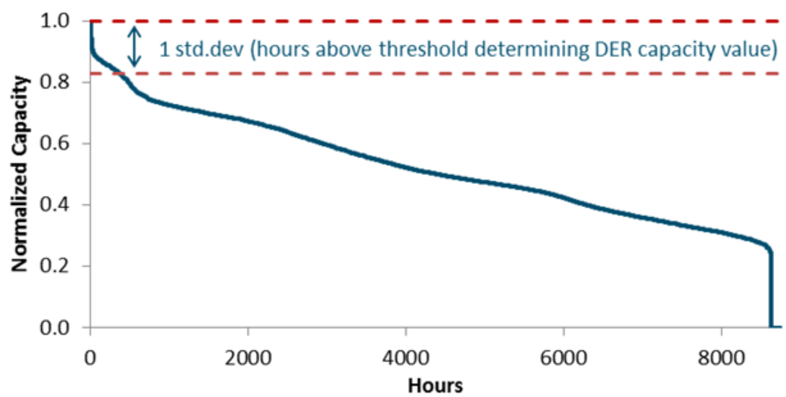
$$
\begin{aligned}
PeakReduction[p,a] \\
&= \max(Load[p,t]\ for\ t\ in\ T) - \max(Load[p,t] \\
&- LoadReduction[p,a,t]\ for\ t\ in\ T)
\end{aligned}
$$

5.4.3.2 Peak Capacity Allocation Factor (PCAF)

The peak capacity allocation factor (PCAF) method is used to determining the contribution of DER measures toward distribution peak load reduction based on the overlap of DER output timing and distribution peak hours.

Peak load hours are defined as the hours where network loads are within one standard deviation of the highest network load. The figure below illustrates how the threshold is determined and applied to the peak period.

PCAF Hours on the Load Duration Curve



The load in the hour below one standard deviation from the top of the load duration curve is the threshold cutoff and is the highest load not to be included in the peak period. Reducing loads in hours at or below the threshold is assumed not to have any capacity value to the system. The relative importance of each hour in reducing load is then quantified as a weighting factor. Weights are calculated for all peak hours in proportion to their level above the threshold. The formula for PCAFs using proportional weights is shown below, where *Thresh[t]* is the load in the threshold hour.

$$PCAF[p][t] = \frac{Max(0, Load[p][t] - Thresh[t])}{\sum_{hr=1}^{8760} Max(0, Load[p][t] - Thresh[t])}$$

Then the peak load reduction is then calculated based on the PCAF and the corresponding load reduction at each hour

$$PeakReduction[p,a] = \sum_{t=1}^{8760} PCAF[t] \times LoadReduction[p,a,t]$$

5.5 Disbenefits Calculation

5.5.1 ANNUAL DISBENEFITS

5.5.1.1 Avoided Transmission Losses

$$AvoidedTransLosses[p,y]$$
$$= AreaMWh[p,y] \times WeightedEnergyAC[y] \times \Delta\mathrm{LossMWh\%[p]}$$
$$+ \mathrm{AreaMW[p,y]} \times \mathrm{AGCC[y]} \times 1000 \times \Delta\mathrm{LossMW\%}[p]$$

Where

$$WeightedEnergyAC[y] = \frac{\sum_{t\in T} EnergyAC[t,y] \times SystemLoad[t,y]}{\sum_{t\in T} SystemLoad[t,y]}$$

T is the set of timesteps in the year y

$AvoidedTransLosses[p,y]$ is the avoided costs ($) for transmission losses at year y after the project p upgrade

$AreaMWh[p,y]$ is energy consumption in the transmission area affected by the project p upgrade

$EnergyAC[t,y]$ is the energy avoided cost at the timestep t

$\Delta\mathrm{LossMWh\%[p]}$ is baseline area average annual loss factor minus average loss factor after the project p is completed.

$\mathrm{AreaMW[p,y]}$ is the peak MW for the affected area

$\mathrm{AGCC[y]}$ is the avoided generation capacity cost in $/kW

$\Delta\mathrm{LossMW\%}[p]$ is baseline area peak loss factor minus peak loss factor after the project p is completed

$SystemLoad[t, y]$ is the system load at the timestep t

5.5.1.2 Avoided Distribution Losses

$$
\begin{aligned}
&AvoidedDistLosses[y] \\
&\qquad = AreaMWh[p, y] \times WeightedEnergyAC[y] \times \Delta\mathrm{LossMWh\%[p]} \\
&\qquad + \mathrm{AreaMW[p, y]} \times (\mathrm{AGCC[y]} + \mathrm{ADC[a, y]}) \times 1000 \times \Delta\mathrm{LossMW\%}[p]
\end{aligned}
$$

Where

$$WeightedEnergyAC[y] = \frac{\sum_{t \in T} EnergyAC[t, y] \times DistLoad[t, y]}{\sum_{t \in T} DistLoad[t, y]}$$

T is the set of timesteps in the year y

$AvoidedDistLosses[p, y]$ is the avoided costs ($) for distribution losses at year y after the project p upgrade

$AreaMWh[p, y]$ is energy consumption in the distribution area affected by the project p upgrade

$EnergyAC[t, y]$ is the energy avoided cost at time step t on year y

$\Delta \mathrm{LossMWh\%}[p]$ is baseline area average annual loss factor minus average loss factor after the project p is completed.

$\mathrm{AreaMW}[\mathrm{p}, \mathrm{y}]$ is the peak MW for the affected area

$\mathrm{AGCC}[\mathrm{y}]$ is the avoided generation capacity cost in $/kW

$\mathrm{ADC}[\mathrm{a}, \mathrm{y}]$ is the avoided distribution cost in $/kW for location a

$\Delta \mathrm{LossMW\%}[p]$ is baseline area peak loss factor minus peak loss factor after the project p is completed

$SystemLoad[t, y]$ is the distribution load at the timestep t

5.5.1.3 Net Avoided Outage Costs

Outage costs are treated in two ways in the model. There are reduced outage costs associated with the T&D investments. Those outage savings are treated as disbenefits and treated the same as distribution capacity values, including adjusting kW impacts for flowfactors.

There are also increased reliability benefits provided to customers that install specific types of DG and storage devices. Those impacts are treated as additional benefits for those measures.

6 Appendix B: Interconnection costs

Interconnection cost is an important metric for quantifying the impact of distributed generators to the distribution system. This tool provides two ways to quantify the costs: the first way is based on a simple interconnection fee which assigns a $/kW costs to each technology, the second one is a more detailed way which looks at the potential outflow upgrade project at each distribution location and technology's contribution to the upgrade based on its operation. Both methods assume the interconnection costs would be incurred by the utility and passed to the customer.

This chapter describe the methodology for both methods.

6.1 Simple Interconnection Fee

This simple interconnection fees method is based on the NEM 2.0 guidelines

These interconnection costs would capture the routine costs to connect customer sited generators, absent the need for capacity upgrades. These costs would be incurred by the utility and passed to the customer.

- Fort customer generators under 1MW
  - PG&E: $145
  - SCE: $75
  - SDG&E: $132
- Customer generators over 1MW

All: $1000 (capacity upgrade costs would be captured in the next section)

This simple interconnection fee is applied to distributed generators including PV, storage, fuel cell generators, and EV if V2G is enabled.

6.2 Detailed Interconnection Costs Estimate

These costs would capture the incremental capacity-related work that the utilities would incur due to excess customer generated power. The costs would be incurred by the utility. The costs would be passed to the customer, consistent with the Interconnection Fees per the NEM 2.0 guidelines.

6.2.1 APPROACH

Each local area will have hosting capacity kW, the corresponding costs to upgrade if the hosting capacity is exceeded, and a forecast of autonomous (natural growth) generation (PV) kW by year as well as a forecast of other DER. DER reductions or increases at the time of the highest generation output will be used to reduce or increase the hosting capacity in each year. Hosting capacity will similarly be increased for forecast demand increases (load growth).

6.2.1.1 For uncontrolled generation

The incremental uncontrolled PV kW would be compared to the adjusted hosting capacity. If the PV exceeds the hosting capacity, then a capacity project would be triggered, and those costs would be added to the cost effectiveness calculations. The capacity projects would be simple unit cost representations of typical projects related to excess generation. The projects could be specified for each area, or a generic value.

Two types of hosting capacity limits and unit costs can be used for each area based on: 1) voltage limit constraints, and 2) thermal limit constraints. The limits and associated costs will be handled separately in the modeling, so an uncontrolled PV could trigger none, one, or both investments.

To the extent that demand increases from DER such as storage or EV can absorb excess generation and defer or eliminate the need for the capacity addition, those cost savings would also be reflected in the cost effectiveness calculations.

6.2.1.2 For controlled generation

For controlled generation, we assume that the generation would be curtailed to avoid excess generation beyond the hosting capability for the area. The cost of the curtailment is currently set to be 0, but in the future version, the cost of curtailment would be

+ Customer: Retail rate of power less non bypassable charges that are not credited to the customer
+ Utility: Increased wholesale cost of supply

The incremental cost of charging from power that would otherwise be curtailed would be zero, which would also improve the economics for a combined solar + storage system. No capacity projects to address excessive generation would be incurred in the controlled generation case.

7 Appendix C: Default database

Category	Input	Sources
System	Avoided costs	SCE, PG&E, and SDG&E avoided costs by climate zones based on the 2018 CPUC Avoided Cost Calculator[6] Avoided ancillary service costs are assumed to be 0
	DA energy prices	Projected CA NP15 and SP15 future DA energy prices based on 2015 historical price data with 2% annual escalation rate
	System Resource Adequacy (RA) Price	For NP15/SP15, use 2017-2021 weighted average capacity price from 2017 CPUC RA Report, assume price remains the same from 2017 to 2048
	Avoided Transmission Capacity Price	For NP15/SP15, use avoided transmission costs in PGE CZ1 dataset
	Ancillary services prices	Projected CA NP 15 and SP15 future ancillary service prices based on 2015 historical price data with 2% annual escalation rate
	System historical load shapes	CAISO 2016 Hourly Load from CAISO OASIS
	System load growth forecast	2018-04-23 CPUC RESOLVE case[7]
	Fuel prices	Natural gas prices are from historical PG&E Gate, Southern California Border, and Southern California City Gate; Gasoline prices are from EIA Annual Energy Outlook 2018[8]; Oli prices in the example are placeholder numbers only
	Marginal Emission Rate	Based on the marginal emission rate in the E3 calculator (2018 update)[9]

[6] http://www.cpuc.ca.gov/general.aspx?id=5267
[7] http://cpuc.ca.gov/General.aspx?id=6442457210
[8] EIA AEO2018 Pacific Region Motor Gasoline End-User Price Forecast: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=70-AEO2018&region=1-9&cases=ref2018&start=2016&end=2050&f=A&linechart=~ref2018-d121317a.15-70-AEO2018.1-9&map=ref2018-d121317a.4-70-AEO2018.1-9&ctype=linechart&sourcekey=0
[9] https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

	Renewable Forecast	2018-04-23 CPUC RESOLVE case[7]
	Default weather data	Zip code 94104 Mean Temperature from NOAA
Distribution system	Distribution system load shapes	The load shape for DPA 1 is from the LNBA tool[10,11]; load shapes for the example Circuit_1107 and Circuit_1102 are scaled based on the example Industrial customer load shapes; load shapes for Rector are based on the DPA1 load shapes and are scaled to the capacity and energy deficiency of the forecasted upgrade in 2018 GNA and DDOR report.: SCE Rector – Riverway No.2 66kV New circuit upgrade
	Distribution system upgrade costs	Rector is based on the 2018 GNA and DDOR report.: SCE Rector – Riverway No.2 66kV New circuit upgrade; DPA1, Circuit 1107 and Circuit 1102 are Based on assumptions in the LNBA tool[10,11]
Financial scenarios	Solar cost assumptions	Based on mid-level estimates from NREL
	Storage cost assumptions	Based on Lazard levelized cost of storage v4.0 E3 internal Pro Forma analysis
Rates		Selected 2019 PG&E and 2018 SCE rates; PG&E: E-19; SCE: TOU-8, TOU-GS-1, TOU-GS-2, TOU-GS-3, Res-D, Res_TOU-D, Res_TOU-EV-1
Customer	Customer load shapes	Based on the Dynamic Load Profiles from three IOUs[12,13,14]
	Customer Energy Efficiency consumption reduction	Based on CPUC Database of Energy Efficiency Resources (DEER)[15]
	Customer EV driving behavior	Based on driving behaviors compiled from NHTS[16] database (including ICEs and EVs)
Technologies	Storage	E3 generic storage input
	PV profiles	Based on the PV shapes in the CPUC Avoided Cost Calculator[6]
	EE profiles	Based on CPUC Database of Energy Efficiency Resources (DEER)[15]

[10] CPUC IDER and DRP Working Groups: https://drpwg.org/growth-scenarios/
[11] Tool download link: https://e3.sharefile.com/share?#/view/sb2965cf362c48399
[12] SCE Dynamic Load Profiles: https://www.sce.com/regulatory/load-profiles/dynamic-load-profiles
[13] PG&E Static Load Profiles: https://www.pge.com/nots/rates/006f1c4_class_load_prof.shtml
[14] SDG&E Dynamic Load Profiles: http://webarchive.sdge.com/customer-choice/customer-load-profiles/customer-load-profiles
[15] http://www.cpuc.ca.gov/general.aspx?id=2017
[16] National Household Travel Survey: https://nhts.ornl.gov/

	EV	Based on the default assumptions of BEV250 in NREL EVI-Pro Lite Tool[17]
	Fuel Cell	E3 generic input
	Water Heater	E3 generic input
	HVAC	E3 generic input

[17] EVI-Pro Lite: https://afdc.energy.gov/evi-pro-lite

8 Appendix D: List of Abbreviations and Acronyms

B/C ratio	Benefit/Cost Ratio
BTM	Behind-the-meter
CEC	California Energy Commission
DA	Day Ahead
DDOR	Distribution Deferral Opportunity Report
DER	Distributed Energy Resource
DGPV	Distributed Generation: Photovoltaic
EE	Energy Efficiency
EPIC	Electric Program Investment Charge
FTM	In-front-of-the-meter
HVAC	Heating, Ventilation, and Cooling
IOU	Investor-owned Utility
IRR	Internal Rate of Return
MACRS	Modified Accelerated Cost Recovery System
NPV	Net Present Value
NWA	Non-Wires Alternative
O&M	Operations & Maintenance
PAC	Program Administrative Cost Test
PCAF	Peak Capacity Allocation Factor
PCT	Participant Cost Test
PPA	Power Purchase Agreement
RFP	Request for Proposal
RIM	Rate Impact Measure Test
ROE	Return on Equity
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SGIP	Self-Generation Incentive Program
T&D	Transmission and Distribution

TRC	Total Resource Cost Test
UI	User Interfaces
V1G	Managed Charging
V2G	Vehicle-to-grid
VoLL	Value of Lost Load