Maine Distributed Generation Successor Program Study:

Final Benefit-Cost Analysis Results and Sensitivity Analyses

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Synapse Energy Economics:
Tim Woolf, Eric Borden, Danielle Goldberg, Paul Rhodes
Sustainable Energy Advantage:
Tom Michelman, Jim Kennerly, Stephan Wollenburg

Agenda

- **The November 17, 2022 workshop discussed inputs, methodology, initial results of the benefit-cost and rate impact analyses, and obtained stakeholder group feedback.**
- **The purpose of today's meeting is to discuss final results of the BCA and sensitivity analyses incorporating stakeholder feedback, and next steps.**

Agenda

- Recap modeled program designs
- Recap key modeling inputs and assumptions
- Final BCA and rate impact results
- Sensitivity analyses
  - *BCA – discount rate, avoided T&D costs*
  - *Storage*

Review of Modeled Program Designs

Resource Blocks

- Resource blocks are chosen to create some diversity in the technologies, locations, and the types of offtakers
  - *Please note that these are not intended to be interpreted as the actual resources expected or preferred in the successor program*
- Generally designed to capture tax benefits provided in the Inflation Reduction Act
- For the initial analysis (Program Cases 1-4), our team proposed six types of resource blocks, representing combinations that result in low costs but also achieve certain policy goals, e.g., LMI customer participation.
- These six blocks were first presented at the October 4th workshop and are described in more detail in the next slides.
- We estimated the costs of each resource block, for each of the programs as described
- For the hybrid case, we proposed 5 of those 6 blocks (excluding the LMI case that only received a 30% ITC)
- Note resource blocks were modified in response to stakeholder input

Resource Blocks (Programs 1-4)

	Technology	Location	Offtakers	IRA LMI Credit	Capacity
Program Options 1, 2, and 3	Roof PV (1 MW)	BTM: Host customer	Host customer	none	93 MW
	Ground PV (5 MW)	FTM: anywhere	50% Res, 50% C&I	none	93 MW
	Ground PV (5 MW)	FTM: anywhere	50% LMI, 25% Res, 25% C&I	none	93 MW
	Ground PV (5 MW)	FTM: Brownfield & LMI neighborhood	50% Res, 50% C&I	10%	93 MW
	Ground PV (5 MW)	FTM: LMI neighborhood	50% Res, 50% C&I	10%	93 MW
	Ground PV (5 MW)	FTM: LMI benefit	50% LMI, 25% Res, 25% C&I	20%	93 MW
	Totals	-----	-----	-----	558 MW

	Technology	Location	Offtakers	IRA LMI Credit	Capacity
Program Option 4	Roof PV (1 MW)	BTM: Host customer	None (wholesale PPA)	none	141 MW
	Ground PV (5 MW)	FTM: anywhere	None (wholesale PPA)	none	141 MW
	~~Ground PV (5 MW)~~	~~FTM: anywhere~~	~~None (wholesale PPA)~~	~~10%~~	not included
	Ground PV (5 MW)	FTM: Brownfield & LMI neighborhood	None (wholesale PPA)	10%	141 MW
	Ground PV (5 MW)	FTM: LMI neighborhood	None (wholesale PPA)	10%	141 MW
	~~Ground PV (5 MW)~~	~~FTM: LMI benefit~~	~~None (wholesale PPA)~~	~~20%~~	not included
	Totals	-----	-----		564 MW

Resource Blocks (Program 5 - Hybrid)

	Taken from Program	Technology	Location	Offtakers	Capacity
Program 5 (Hybrid of Programs 3 & 4)	3	Roof PV (1 MW)	BTM: Host customer	Host customer	84 MW
	4	Ground PV (5 MW)	FTM: anywhere	None (wholesale PPA)	131 MW
	~~3~~	~~Ground PV (5 MW)~~	~~FTM: anywhere~~	~~50% LMI, 25% Res, 25% C&I~~	Not included
	4	Ground PV (5 MW)	FTM: Brownfield & LMI neighborhood	None (wholesale PPA)	131 MW
	4	Ground PV (5 MW)	FTM: LMI neighborhood	None (wholesale PPA)	131 MW
	3	Ground PV (5 MW)	FTM: LMI benefit	50% LMI, 25% Res, 25% C&I	84 MW
		Totals	-----	-----	560 MW

Key Program Design Elements that Affect Costs

1. Competitive procurement vs. administratively set prices
   - The legacy program ("Program 1") was based on electric *rates* not *costs* of DG.
2. Attributes claimed by the utility
   - From a DG developer perspective, the more revenues that are claimed by the utility the cheaper financing is ("hedged revenues"). This has a significant impact on DG costs.
3. The group(s) that claim the monetary benefits of DG ("offtakers")
   - Cost shifting – If certain customer groups receive the benefits of DG, other ratepayers pay for this.
     - No effect on total cost, but effect on *participating* vs. *non-participating* customers can be significant

Program:	**Program 1**	**Program 2**	**Program 3**	**Program 4**	**Program 5**
Program Title:	**Original Tariff program**	**Fixed Future Payments**	**Moderate Hedge**	**Wholesale PPA**	**Hybrid**
Attributes that go to utility	Energy	Energy	Energy, RECs	Energy, RECs	Energy, RECs
Eligible customers for offtakers	C&I	All/varies by block	All/varies by block	none	Some blocks (1 and 6)
Setting initial payments	rates	competitive	competitive	competitive	competitive
Setting future payments	varies with rates	fixed	fixed	fixed	fixed

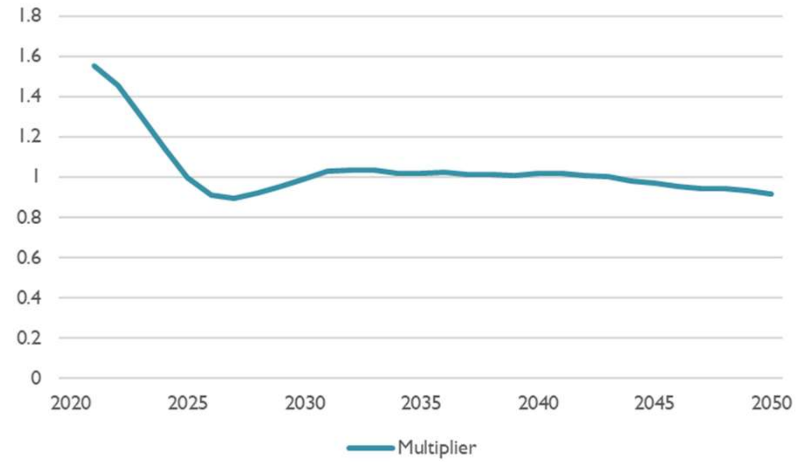
Review of Key Methods and Inputs

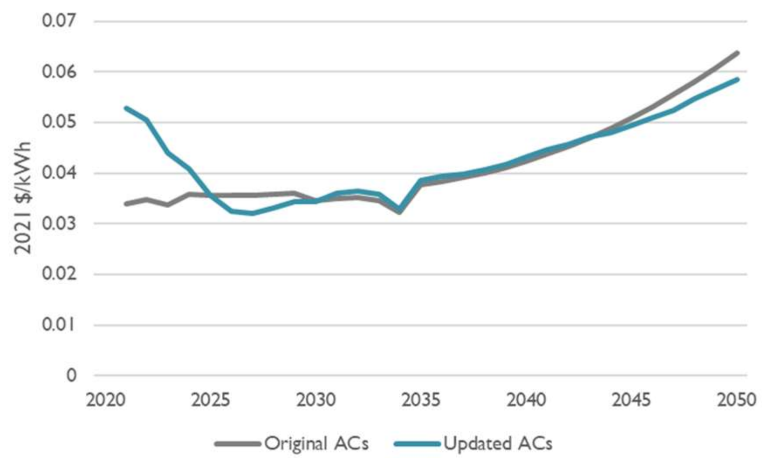
Benefits and Costs Quantified in the BCA

	Type of Impact	Impact	Benefit or Cost?	Method
Impact rates	Generation	Avoided Energy Cost	Benefit	AESC 2021
		Avoided Capacity Cost	Benefit	AESC 2021
		Avoided Environmental Compliance	Benefit	AESC 2021
		Avoided RPS Compliance Costs	Benefit	AESC 2021
		Market Price Effects ("DRIPE")	Benefit	AESC 2021
	Transmission	Avoided PTF Costs	Benefit	Efficiency Maine assumptions
		Avoided Non-PTF Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
	Distribution	Avoided Distribution Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
	General	Renewable Energy Credit Prices	Benefit	Sustainable Energy Advantage (SEA)
		DG Costs	Cost	Based on program design and total cost from SEA
		Storage Costs (Sensitivity)	Cost	No storage costs in initial run; presented today as a sensitivity to "base case"
		Program Administration Costs	Cost	Input from utilities ($600,000 for first 5 years, $300,000 for remaining generation period)
Don't Impact rates	Societal	Avoided CO_2	Benefit	AESC 2021
		Avoided NOx	Benefit	AESC 2021

Updated Avoided Costs for Energy

- To reflect near-term high gas prices, we updated the avoided costs for electric energy using EIA's AEO (Annual Energy Outlook) 2022
- We calculated the percent difference in prices compared to AEO 2020 to determine a multiplication factor (shown above right)
- We multiplied the original avoided costs by this factor to determine updated avoided costs (below right, blue)
    - Values shown in $2021 were converted to $2022
- The result has small near-term implications from 2027 (the first year of assumed production) through 2030 before mostly aligning with the original ACs through the end of the study period

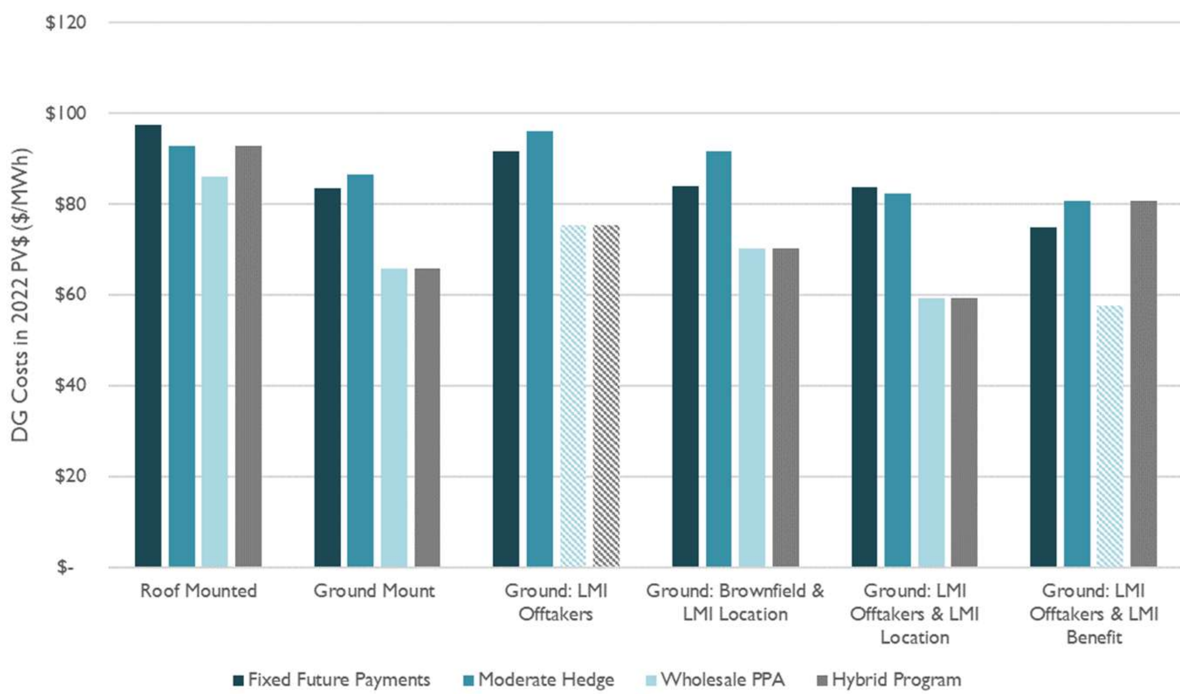




Program Costs

- Program costs include
  - All the costs necessary to make the developer whole plus
  - The utility program administration costs
- The developer's costs are estimated using SEA's CREST model
  - Estimates a constant stream of nominal dollar payments for 20-year life of project.
  - These nominal values are adjusted for inflation and discounted to get present value 2022 dollars.
- We estimate the program costs as a distinct "Program Charge"
  - Note: determining the method of cost recovery from ratepayers is outside the scope of our analysis

Modeled DG Costs by Program or Block (2022 PV$)



These are the costs for the first year, where we assume developers enroll in 2024 and operation commences in 2027.

In later years, costs are slightly lower as technologies mature.

Note: Shaded blocks shown for illustrative purposes. These were not included in our analysis.

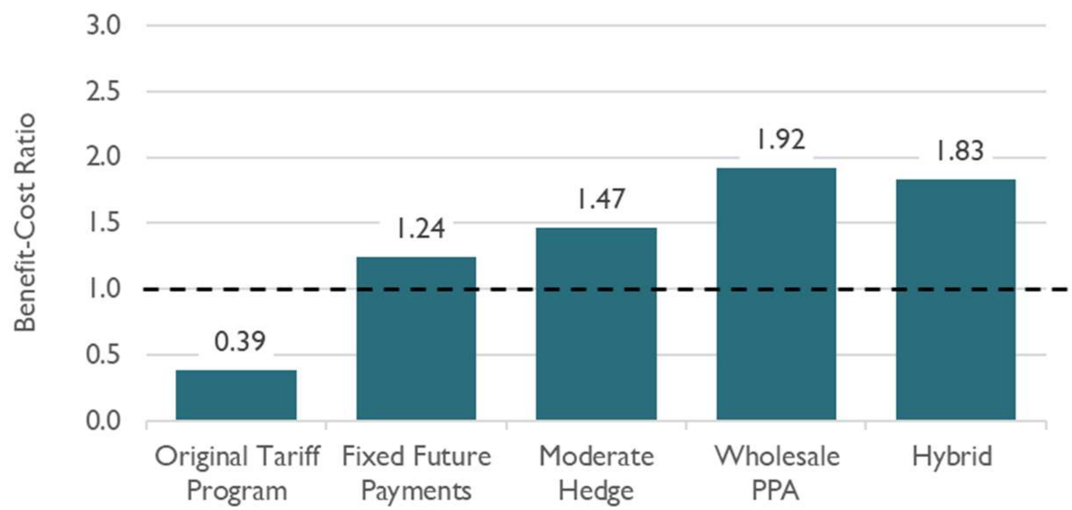
Avoided Costs that Impact Rates

- We use four rates within our analysis: generation, transmission, distribution, other (includes all riders, stranded costs)
  - The sum of these rates are the retail rates seen by customers
- Which ACs impact the **generation rate**?
  - Price suppression (DRIPE)
  - Reliability
  - REC revenue
- Which ACs impact the **transmission rate**?
  - Avoided PTF
  - Avoided Non-PTF transmission (BTM only)
- Which ACs impact the **distribution rate**?
  - Avoided Distribution (BTM only)
- Which ACs impact the **other rates**?
  - None

Final Results of Initial Successor Program Designs

BCA Results: Benefit-Cost Ratios

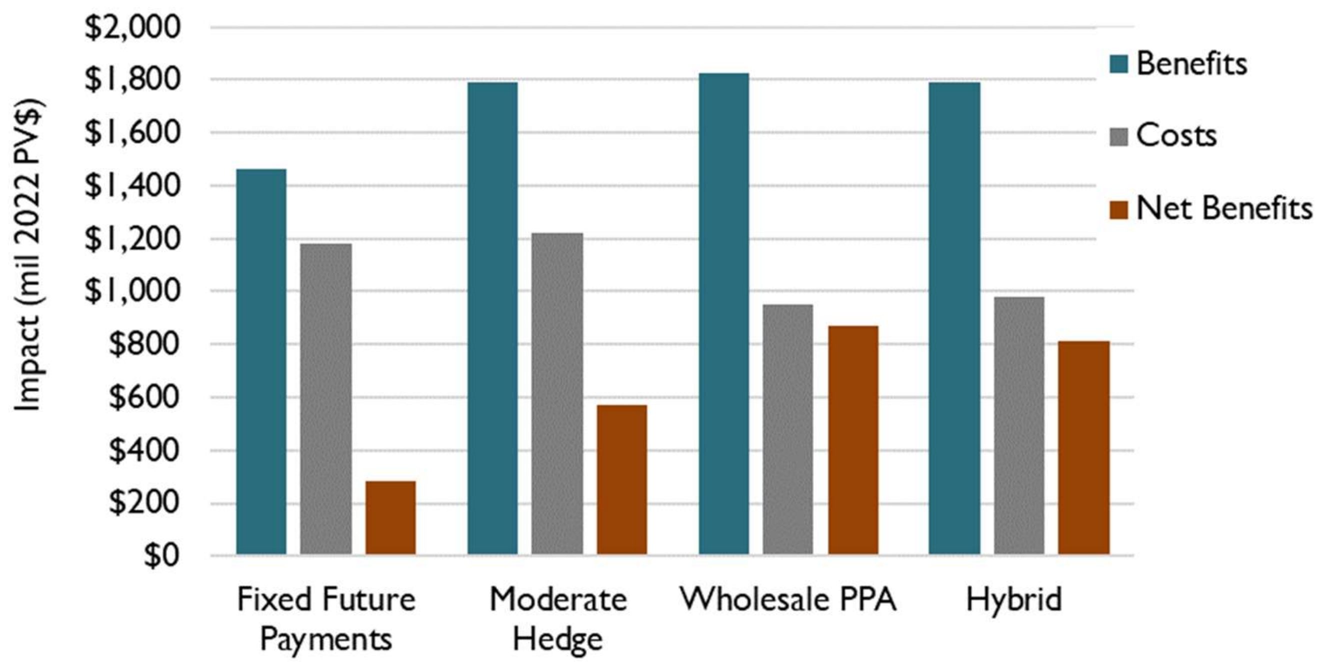
- Programs 2 through 5 are cost-effective: modeled benefits are greater than costs
- The Wholesale PPA program is the most cost-effective option due primarily to the low DG costs of this program
- The hybrid program is slightly less cost-effective than the wholesale PPA due to a different modeled resource mix, but achieves a greater variety of policy goals, namely more direct benefits to low- and middle-income customers
  - Both wholesale and hybrid options highly cost-effective (benefit-cost ratios of 1.92 and 1.83, respectively)
- As the hybrid program demonstrates, program designs can be modified to meet policy objectives
  - This might result in lower net benefits than the wholesale PPA model but allows for the achievement of policy objectives



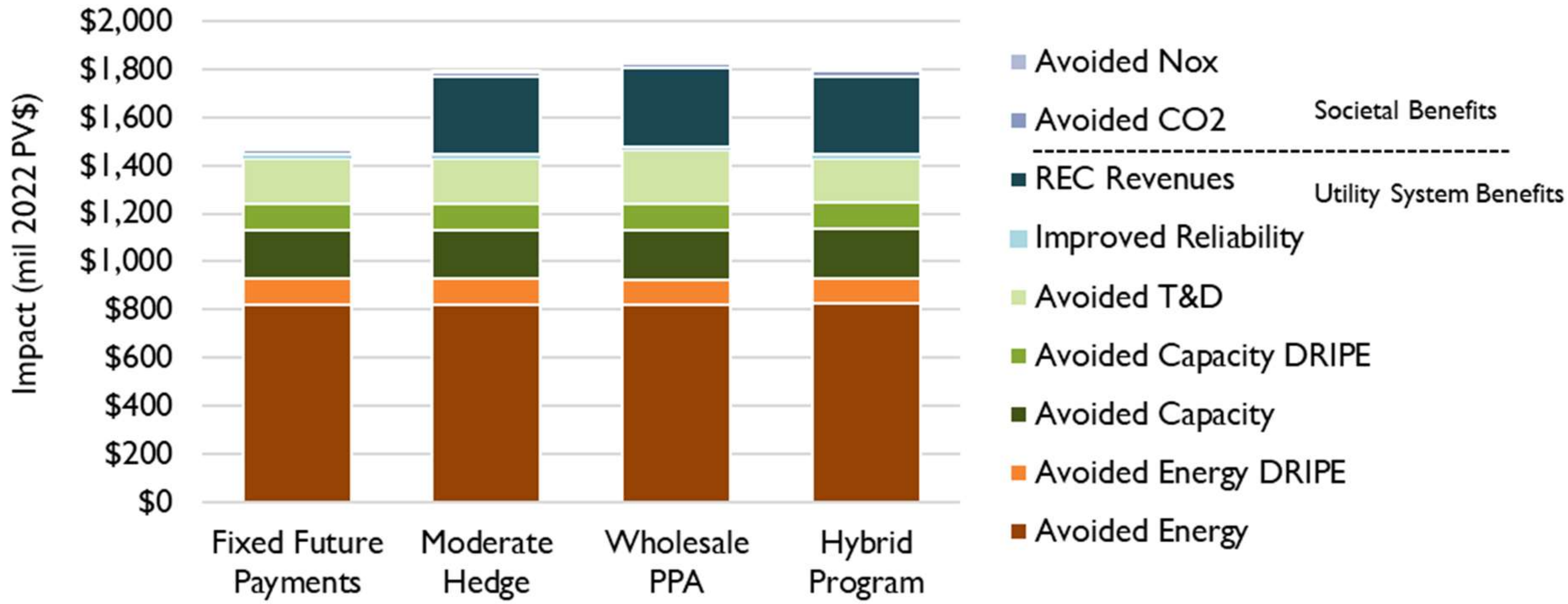
BCA Results: Benefits, Costs, and Net Benefits

Net Benefits:

- Fixed Future Payments: $282 million
- Moderate Hedge: $569 million
- Wholesale PPA: $872 million
- Hybrid: $810 million

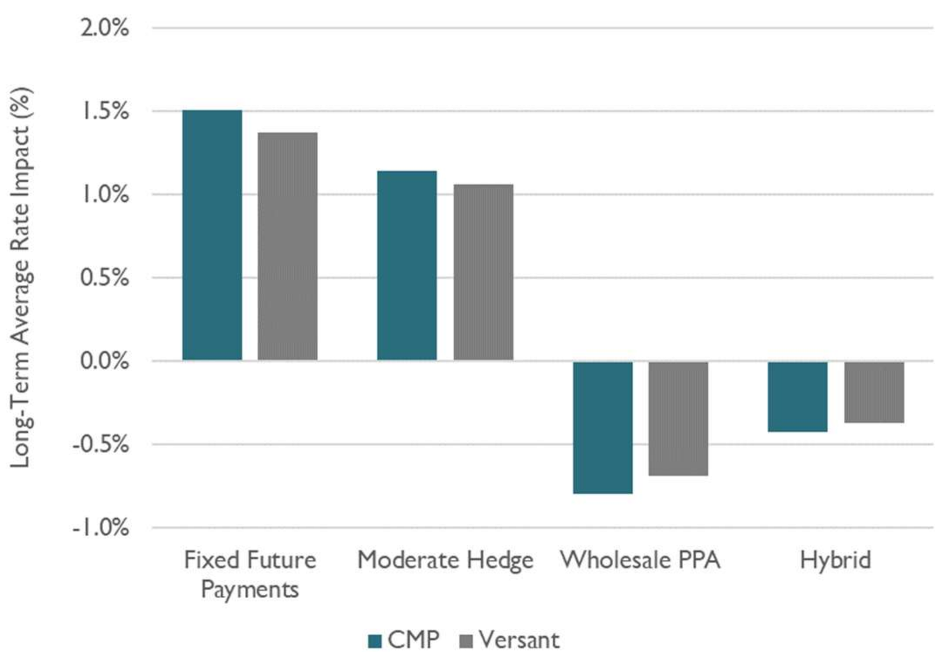


BCA Results: Benefit Details



Rate Impact Results: System Average

Change in rates: percent



Change in rates: ¢/kWh

For the fixed future payments and the moderate hedge cases:

- Most of the benefits flow to offtakers, which reduces participant bills and increases non-participant rates

For the wholesale PPA cases:

- All benefits flow to all customers, which does help reduce rates

Bill Impact Results: Typical CMP Residential Customer

- All customers (within each rate class) experience the same rate impacts
- But the bill impacts vary
  - Participants (offtakers) receive a bill credit, which reduces the total bill
  - Non-participants' bill impact is the same as the rate impact

Program	Non-Participants		Participants	
	Bill Impacts		Bill Impacts	
	($/month)	(%)	($/month)	(%)
Fixed Future Payments	$1.47	1.5%	-$5.43	-3.7%
Moderate Hedge	$1.12	1.2%	-$5.95	-4.1%
Wholesale PPA	-$0.78	-0.8%	There are no offtakers	
Hybrid	<= -$0.42	<= -0.4%	There are not many offtakers	

These results are for a CMP typical residential customer.

The general magnitudes and directions will be similar for Versant customers.

Storage Case

Storage – Input Assumptions

- SEA provided estimated storage costs based on internal research
- The assumptions were adjusted after receiving stakeholder feedback
- Values below reflect adopted assumptions

	Unit	Medium Storage	Large Storage
PV Capacity	kW_{DC}	1,300	6,500
Storage Capacity	kW_{DC}	325	1,625
Duration	Hours	4	4
CAPEX	Nominal $	$1,080,950	$3,473,438
OPEX	Nominal $/yr	$7,472	$24,292

Storage – Operational Assumptions

- Storage dispatch approach
  - Enormous variety of ways that storage could be dispatched, depending on primary use-case, who controls the battery, etc.
  - Modeling approach agnostic to specific program design, and is intended to represent a generic future that could be in line with a number of different requirements for storage
- Assumption of simplified storage dispatch schedule
  - Storage used to capture clipped energy from solar (DC output from panels that exceeds inverter rating stored and injected into grid later)
  - Storage regularly dispatched 3pm to 8pm every non-holiday weekday in June, July, and August, based on Energy Storage Solutions program design in CT
- Storage capacity benefits
  - As noted above, specific benefits of storage highly contingent upon how it is dispatched (which would be influenced by a number of other program design decisions)
  - T&D benefits most uncertain; we adopt conservative assumptions
  - We apply the following factors to storage capacity value:
    - Avoided generation (capacity and capacity DRIPE): 90%
    - Avoided transmission expenses: 20%
    - Avoided distribution expenses: 10%

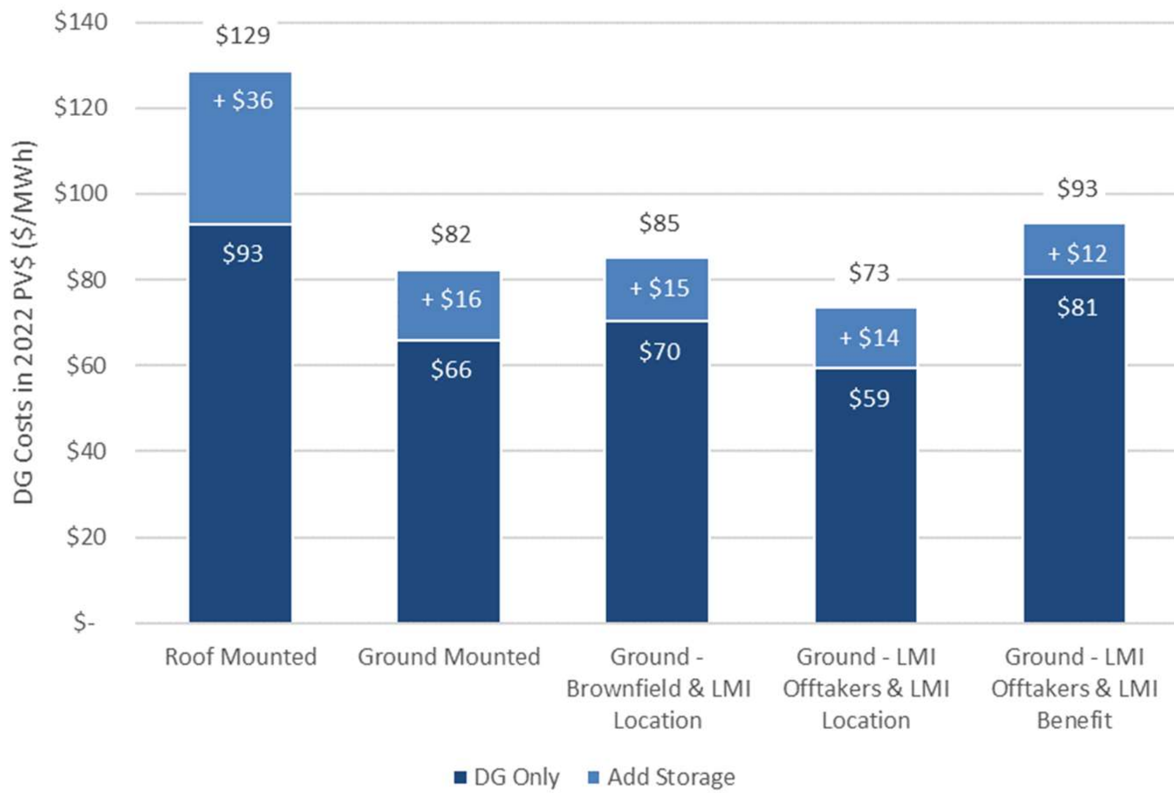
Storage – Impact on Revenue Requirement

- Increases in CapEx and OpEx and changes in net generation due to adding storage incorporated into CREST model, resulting changes to solar revenue requirements, below

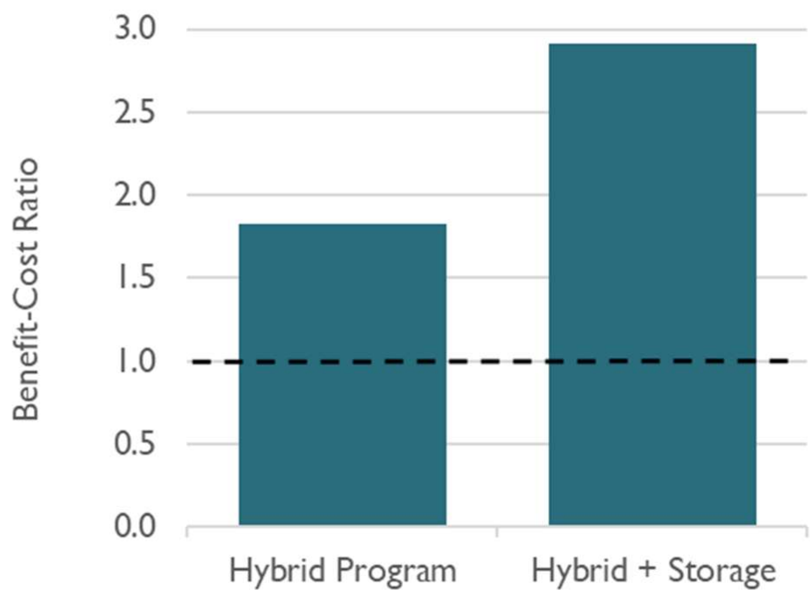
Change in Revenue Requirements From Adding Storage by Resource Block and Selection Year ($/MWh, Hybrid Program Case)

	2024	2025	2026	2027	2028
Large Commercial Roof Mounted	71.30	63.30	58.45	54.80	51.55
Large Ground Mount	32.75	27.45	25.90	24.50	23.65
Large Ground Mount (Brownfield/Other Energy Community)	29.40	25.35	23.90	23.55	21.00
Large Ground Mount (LMI Located in Low-Income/Disadvantaged Community)	27.95	25.25	23.50	22.15	21.20
Large Ground Mount (LMI + Low Income Benefit Project)	24.75	22.80	21.00	19.80	18.65

Storage Case: Costs



Storage Case: Benefit-Cost Ratios

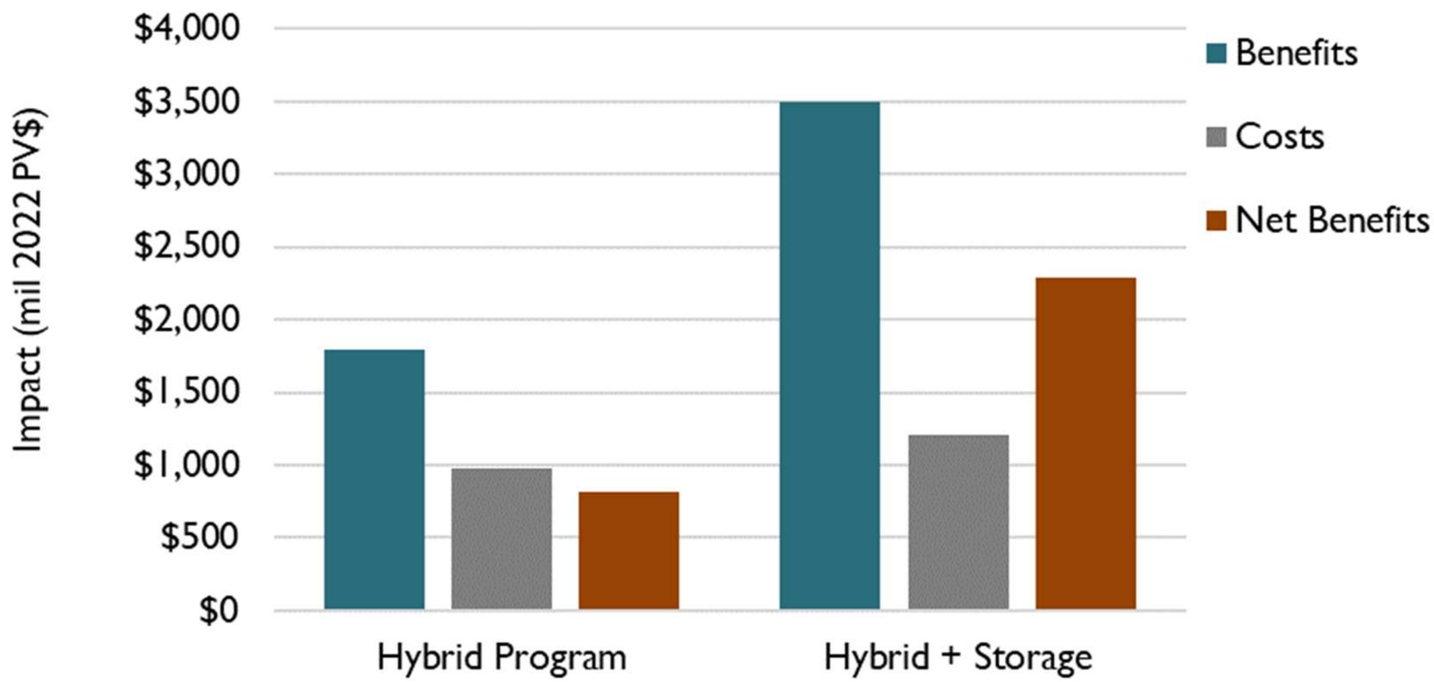


Storage Case: Benefit, Costs, and Net Benefits

The addition of storage increases benefits much more than the increase in costs.

Net Benefits:

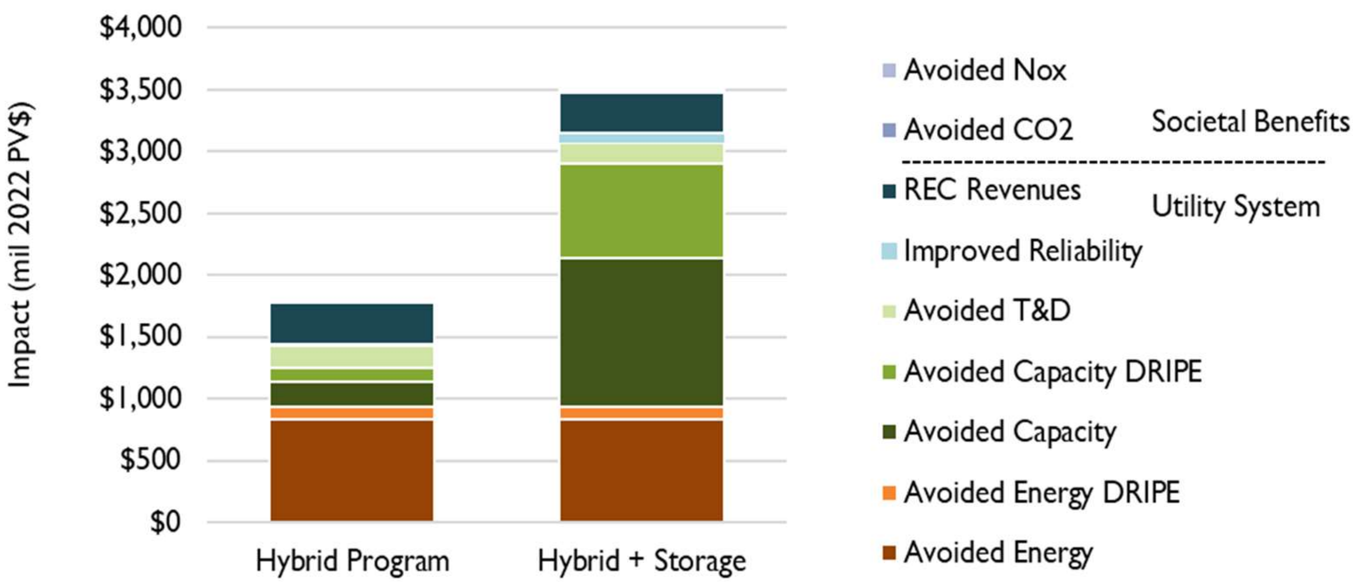
- Hybrid: $810 million
- Hybrid + Storage: $2,289 million



Storage Case: Benefit Details

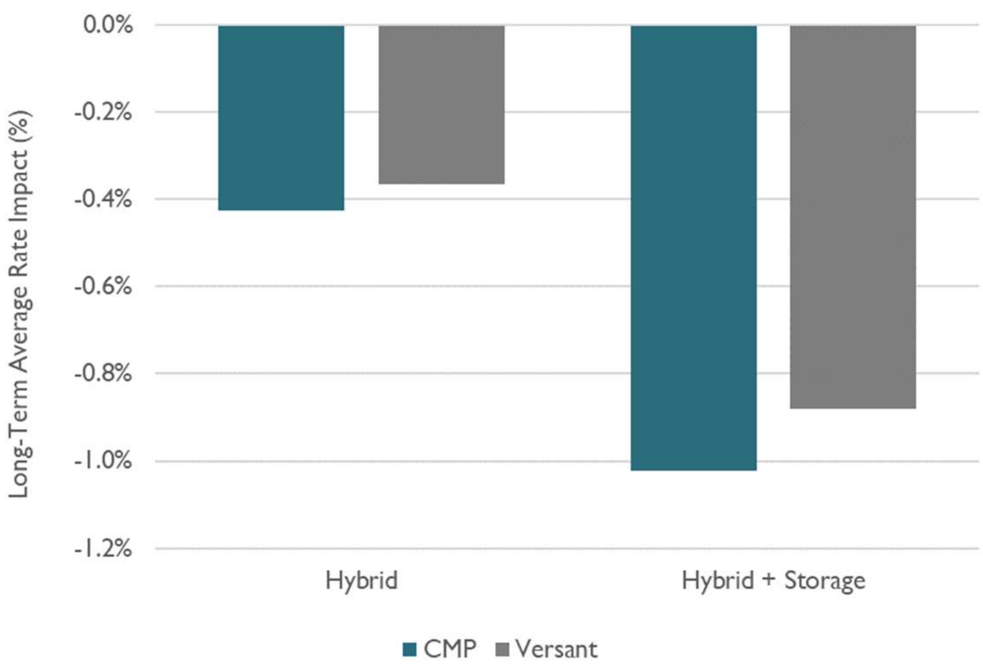
Storage Benefits:

- Significant increases to the avoided capacity and avoided capacity DRIPE.
- Modest increases to the avoided T&D
- No appreciable change the amount of generation, the production of RECs, or the reduction in GHGs.

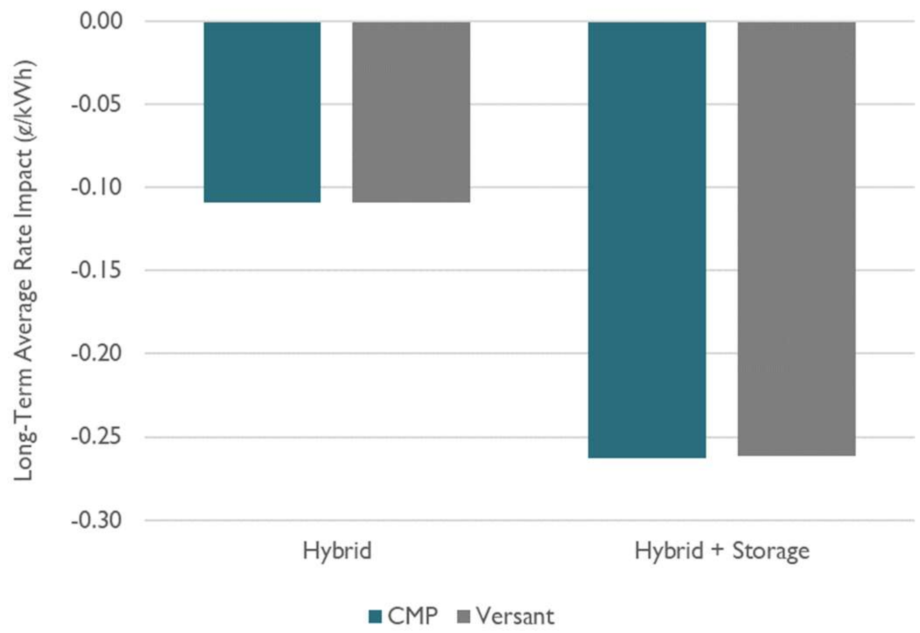


Storage Case: Rate impacts – System Average

Change in rates: percent



Change in rates: ¢/kWh



Sensitivity Analyses

Sensitivity Analyses

- It is important to perform sensitivity analyses on inputs that are the most uncertain and impactful
  - The analyses should utilize a range of reasonable assumptions to test the robustness of primary modelling results

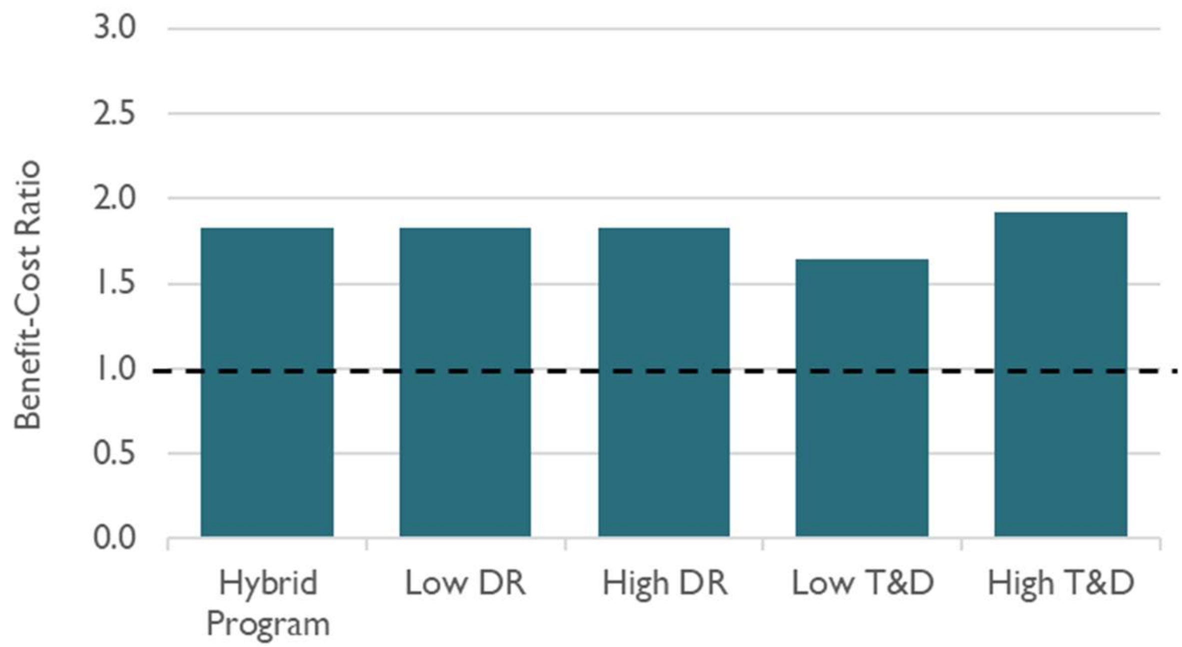
- We performed four sensitivities:
  1. Low discount rate
  2. High discount rate
  3. Low avoided T&D
  4. High avoided T&D

	Low DR	Base Case	High DR
Discount Rate (% Real)	1.6%	2.8%	1.6%

		Low T&D	Base Case	High T&D
BTM ($/kW-year)	Distribution	$0	$250	$375
	Non-PTF transmission	$0	$40	$60
	Non-PTF other	$0	$20	$30
BTM & FTM ($/kW-year)	Maine PTF	$0	$97	$146

Sensitivity Results: Benefit-Cost Ratios

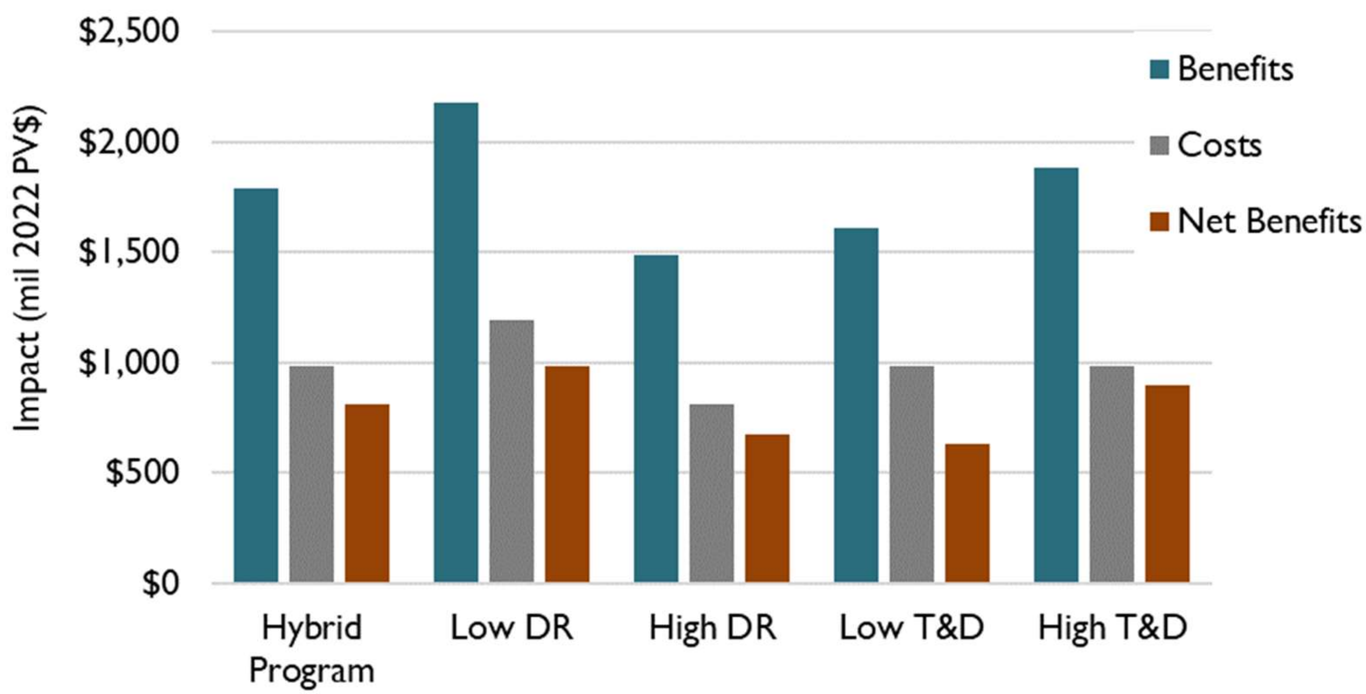
- The discount rates do not affect the BCRs much because the benefits and the costs are spread roughly equally across the study period.
- The high and low T&D assumptions have a noticeable effect on the BCRs, but the program remains cost-effective in both sensitivities.



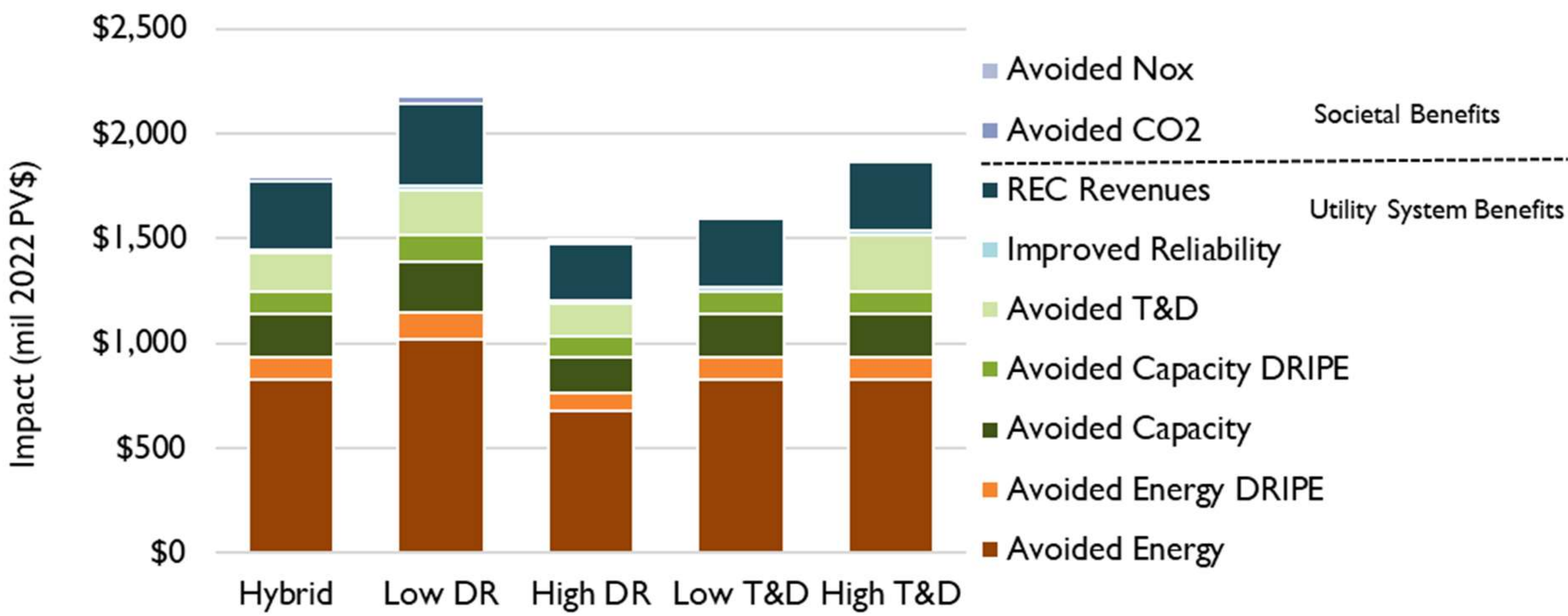
Sensitivity Results: Benefits, Costs, and Net Benefits

Net Benefits:

- Hybrid: $810 million
- Low Discount Rate: $985 million
- High Discount Rate: $672 million
- Low Avoided T&D: $629 million
- High Avoided T&D: $901 million

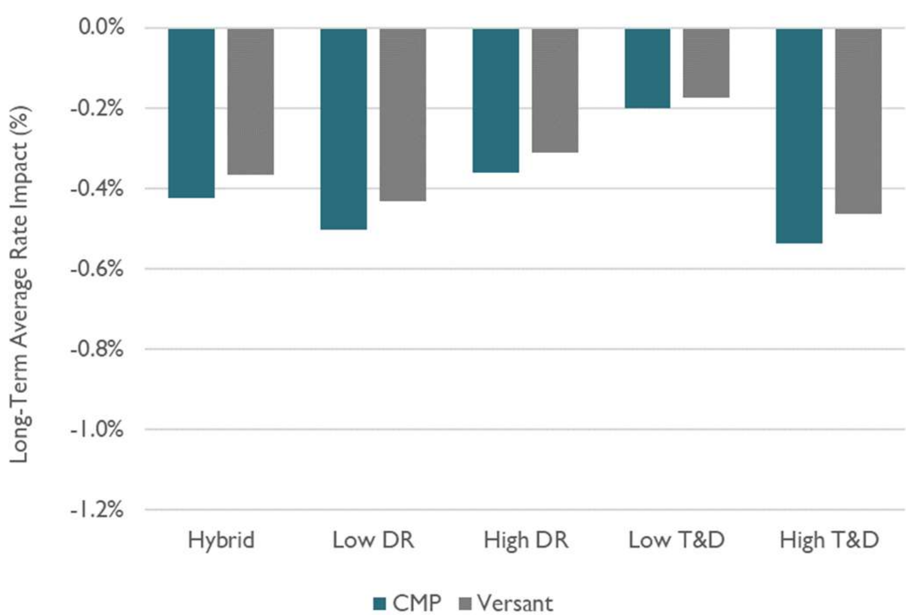


Sensitivity Results: Benefits



Sensitivity Results: Rate Impacts

Change in rates: percent



Change in rates: ¢/kWh