Maine DG Successor Program Study

Distributed Generation Stakeholder Group

Workshop #4: Draft Results of Economic Evaluation

NOTE: these slides were updated following the November 17 presentation to correct axis labels on certain charts

November 17, 2022

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Outline of today's meeting

Benefit-cost analysis

- Inputs and methodology
- Initial results

Rate impact analysis

- Inputs and methodology
- Initial results

Straw proposal

Next steps

- Sensitivities
- Future meetings

Benefit-Cost Analysis: Methods and Inputs

These BCA methods and inputs are based on industry best practices. Many of them have been presented and discussed at previous DG Stakeholder Group Workshops. Slide decks for these workshops are available here:

- Workshop 1: August 31, 2022
- Workshop 2: September 20, 2022
- Workshop 3: October 4, 2022

Some of these inputs are based on information provided by CMP and Versant, as indicated in the slides below.

Draft methods: utility system impacts

Type of Impact	Impact	Method
Generation	Energy	AESC 2021
	Capacity	AESC 2021
	Environmental Compliance	AESC 2021
	RPS Compliance Costs	AESC 2021
	Market Price Effects	AESC 2021
Transmission	PTF	Efficiency Maine assumptions
	Non-PTF	Efficiency Maine assumptions – only applied to BTM
Distribution	Distribution	Efficiency Maine assumptions – only applied to BTM
General	Renewable Energy Credit Prices	Sustainable Energy Advantage (SEA)
	Utility Portion of DG Costs	Based on program design and total cost from SEA
	Utility Portion of Storage Costs	No storage costs in initial run
	Program Administration	Input from utilities ($600,000 for first 5 years, $300,000 for remaining generation period)
	Utility Performance Incentives	There are no performance incentives for DG
	Credit and Collection	Efficiency Maine does not assume a value for this. This impact is too small to quantify for this purpose.
	Risk, Reliability, Resilience	Address qualitatively

Draft methods: non-utility system impacts

Type of Impact	Impact	Method
Participant	Participant Share of DG Cost	Based on program design and total cost of DG from SEA
	Participant Benefits	Address qualitatively
Other fuels	Other fuels	Not relevant for the DG technologies assumed in this study
Low-income	Low-income	Address qualitatively & address in program design
Societal	GHG emissions	AESC
	Other environmental	NOx from AESC 2021, other impacts from IMPLAN
	Macroeconomic	Separate from BCA. IMPLAN analysis. Results will be presented in job-years.
	Risk	Address qualitatively
	Reliability & Resilience	Address qualitatively
	Energy equity	Address qualitatively

Draft BCA assumptions: planning assumptions

Utilities

- We model CMP & Versant together, to provide statewide weighted-average results
- Results are generally applicable to each utility

Installation Dates & Study period

- Assume that projects enroll in the program in 2024-2028
- Assume that there is a three-year delay between enrollment and operation
- Study period to include 25 years (DG operating life) after 2028

Discount rate

- Use the same rate as energy efficiency programs: 2.8% real
- Costs and benefits are discounted to 2022 PV$.

Avoided energy and capacity costs

- Use hourly avoided costs from AESC 2021, grouped into logical periods:
- Winter, summer; on-peak and off-peak for each

AESC 2021 Case

- All-In Climate Policy Sensitivity
- Assumes energy efficiency plus increased levels of electrification & clean energy

Draft BCA assumptions: miscellaneous

- DG program administration costs
  - We assume these are roughly $600,000 per year, based on estimates from CMP and Versant.
- Avoided T&D costs
  - All DG technologies assumed to avoid Maine PTF (regional transmission) costs
    - These values are from 2021 AESC ~20$/kW-yr values
  - Only BTM DG technologies assumed to avoid any non-PTF transmissions and distribution costs
    - We assume these are the same as those used in Maine EE programs:
      - Distribution: ~250$/kW-yr
      - Non-PTF transmission: ~40$/kW-yr
      - Non-PTF other: ~20$/kW-yr
- T&D upgrade costs
  - These are included in the DG costs because developers are required to pay these
- Value of DG capacity rights
  - We assume that utilities will not bid these into the FCM and thus will not get revenue from them.

Draft BCA assumptions: retail price forecasts

Retail electricity price forecast impacts on analysis

- BCA: Small general service (SGS) price forecast affects the cost of the Original Tariff Program
- Rate Impacts: Price forecast will have a very small effect because the analysis captures the difference between two forecasts

Generation: rate escalated based on energy and capacity market price forecasts

CMP T&D: rate escalated each year as proposed by CMP three-year rate plan:

- 2023: 6.1%, 2024: 1.9%, 2025: 1.4%, 2026: 1.3%, 2027 and beyond: 1.2% (real)

Versant Transmission:

- rate escalated to 2023 at 2.5%, after that use same escalation rates as CMP (real)

Versant Distribution:

- rate escalated to 2023 at 29.45%, after that use same escalation rates as CMP (real)

Stranded Costs rider:

- assume this is 0.2 ¢/kWh in 2023 and escalates at 2% (real)

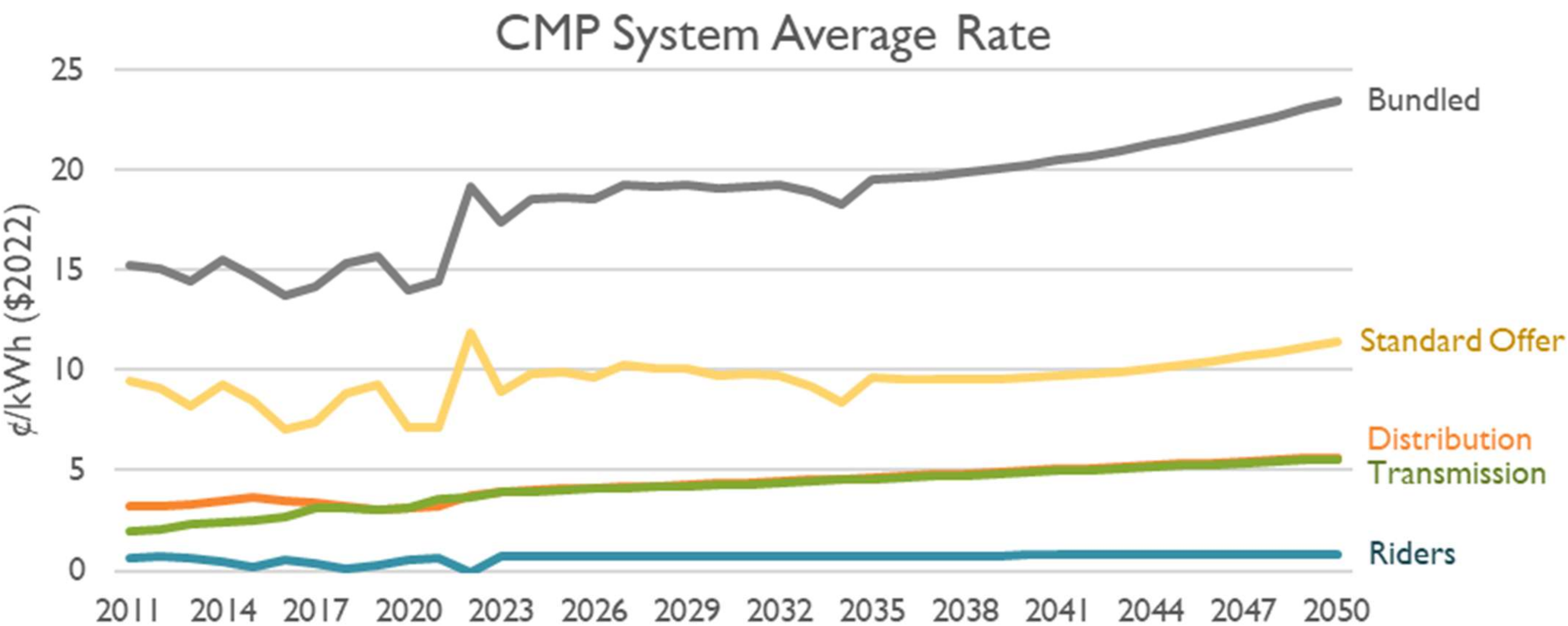
Efficiency rider:

- remains the same as 2022 (real)

Electric Lifeline Program rider:

- remains the same as 2022 (real)

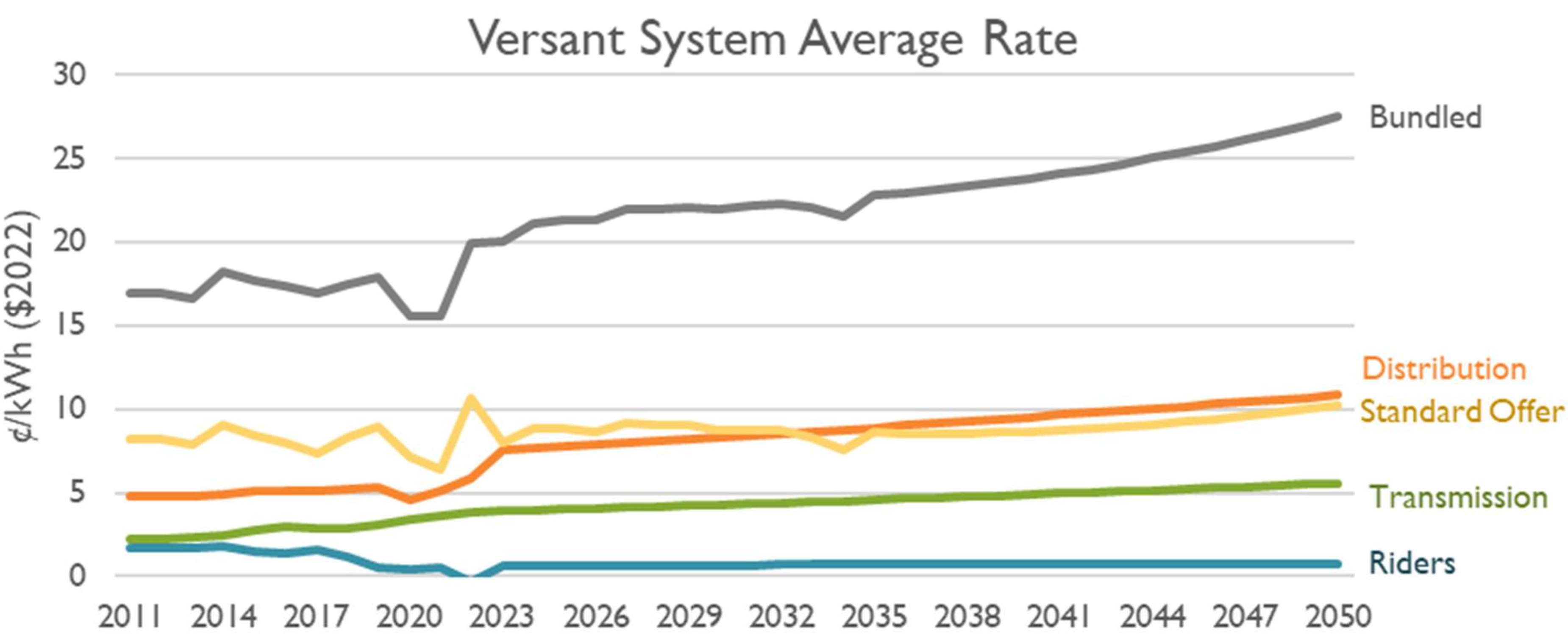
Electric retail price forecasts: for modeling purposes



The standard offer rate does not reflect the recent/proposed increase.
That could be accounted for in the next draft of these results.

These forecasts are developed using long-term averages and are not intended to capture effects of specific events, either in the in the short-, medium-, or long-term. The forecasts are intended for BCA and rate impact assessment purposes and do not represent any entity's expectations about actual future outcomes.

Electric retail price forecasts: for modeling purposes



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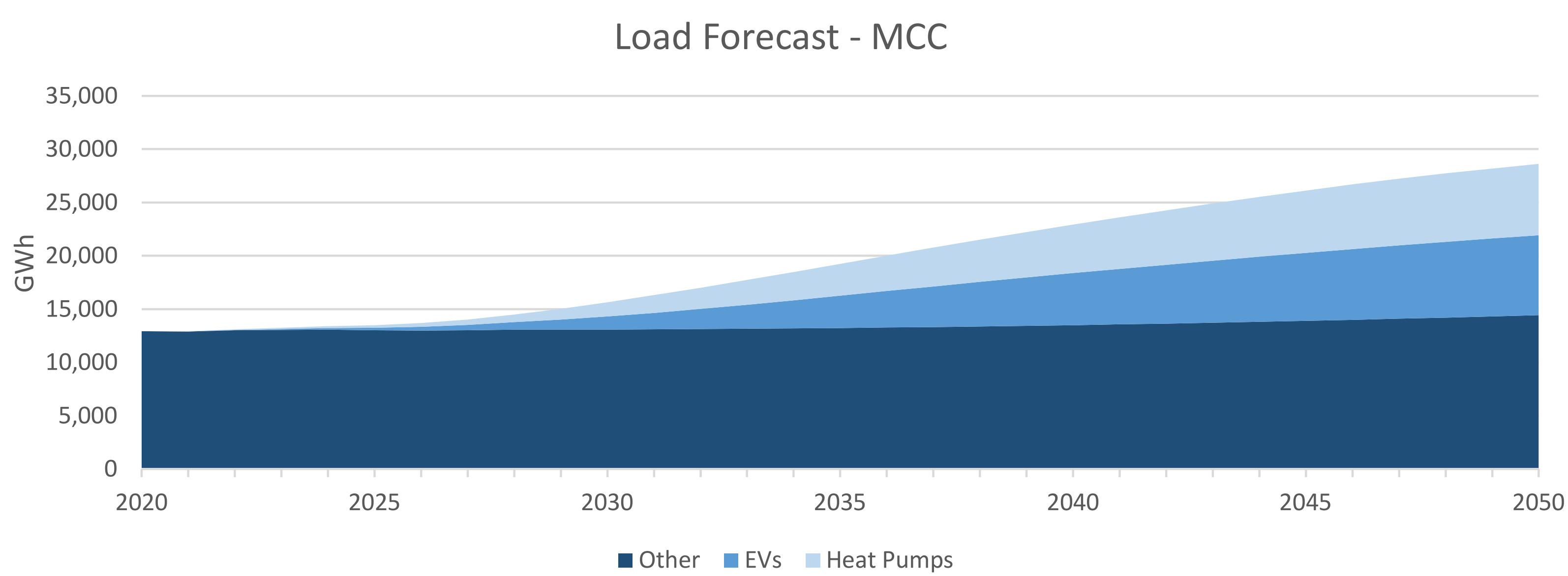
Draft BCA assumptions: electricity load forecasts

Retail electricity load forecast impact on this analysis

- BCA: load forecast has no effect
- Rate Impacts: load forecast will have a very small effect because the analysis captures the difference between two forecasts

Choice of electricity load forecast

- We assume the load forecasts from the Maine Climate Council report. These have the most relevant forecasts of EV, electrification, and DERs.
- The other options (ISO-NE CELT Report and AESC) have similar results and any differences will have little to no impact on the analysis.



Program options

Option #:	Option 1	Option 2	Option 3	Option 4
Program Title:	**Original Tariff program**	**Minimal Hedge**	**Moderate Hedge**	**Wholesale PPA**
Attributes that go to utility	Energy	Energy	Energy, RECs	Energy, RECs
Eligible customers for offtakers	C&I	all	all	none
Setting initial payments	rates	competitive	competitive	competitive
Setting future payments	varies with rates	fixed	fixed	fixed
Impacts on offtakers bills	bill credits	bill credits	bill credits	not applicable
Bill credit period	month	month	month	not applicable
Bill credit type	monetary	monetary	monetary	not applicable
Contract term (years)	20	20	20	20
Offtaker enrollment	developer	developer	developer	not applicable

- The Original Tariff Program is based on the first iteration, where the T&D rate is based on a forecast of T&D rates.
- It is unclear if Option 4 is compliant with LD 936's requirement that any eligible DG project have "identified residential, commercial and institutional customers."

Original tariff program

This program has been capped and reformed under bipartisan legislation signed earlier this year, which decoupled the program from retail rates that can be volatile.

This program was modeled here as a benchmark for comparison with new potential successor programs.

- It is not being included here as a potential successor program.

This program provided payments based on retail electric rates:

- 100% of standard offer service charge
- 75% of transmission and distribution charge

This payment structure is fundamentally different from the other program options modeled here, which are based on the cost of the DG resources

The forward-looking BCA presented here is not intended as a retroactive measurement of the previous program, given that it's applied for a 2024-2028 program period rather than a historical period.

Resource blocks

- Resource blocks are chosen to create some diversity in the technologies, locations, and the types of offtakers.
- We propose 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 presented in discussed at the October 4 workshop and are described in more detail below.
- SEA estimated the costs of each resource block, for each of the programs as described
- Some of the key SEA staff are unable to attend this workshop but they will attend the follow-up workshop on Nov 22 to discuss the details of their cost estimates.

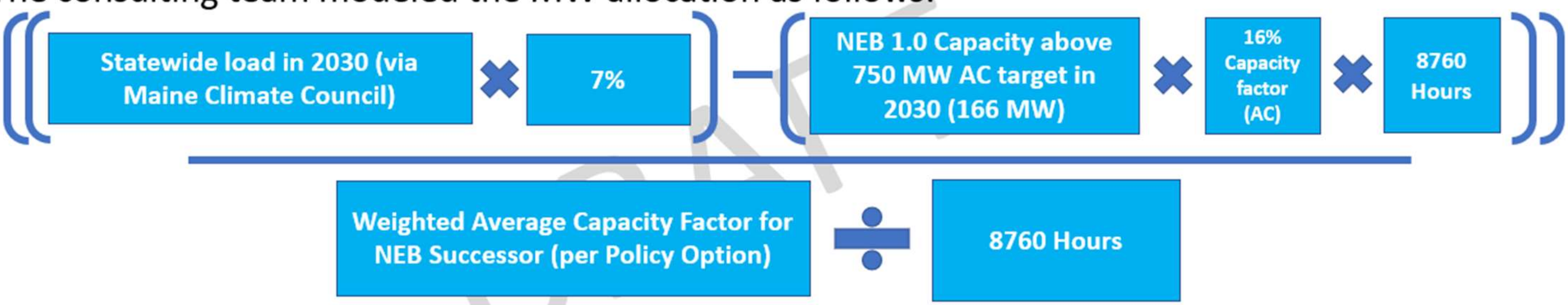
Resource blocks

	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	10%	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	All customers	none	141 MW
	Ground PV (5 MW)	FTM: anywhere	All customers	none	141 MW
	~~Ground PV (5 MW)~~	~~FTM: anywhere~~	~~All customers~~	~~10%~~	not included
	Ground PV (5 MW)	FTM: Brownfield & LMI neighborhood	All customers	10%	141 MW
	Ground PV (5 MW)	FTM: LMI neighborhood	All customers	10%	141 MW
	~~Ground PV (5 MW)~~	~~FTM: LMI benefit~~	~~All customers~~	~~20%~~	not included
	Totals	-----	-----		564 MW

Capacity targets for the successor program: method

- Per statute, the MW target for the NEB successor is calculated as 7% of load, less any development from the initial NEB program in excess of the 750 MW program target
- The consulting team modeled the MW allocation as follows:



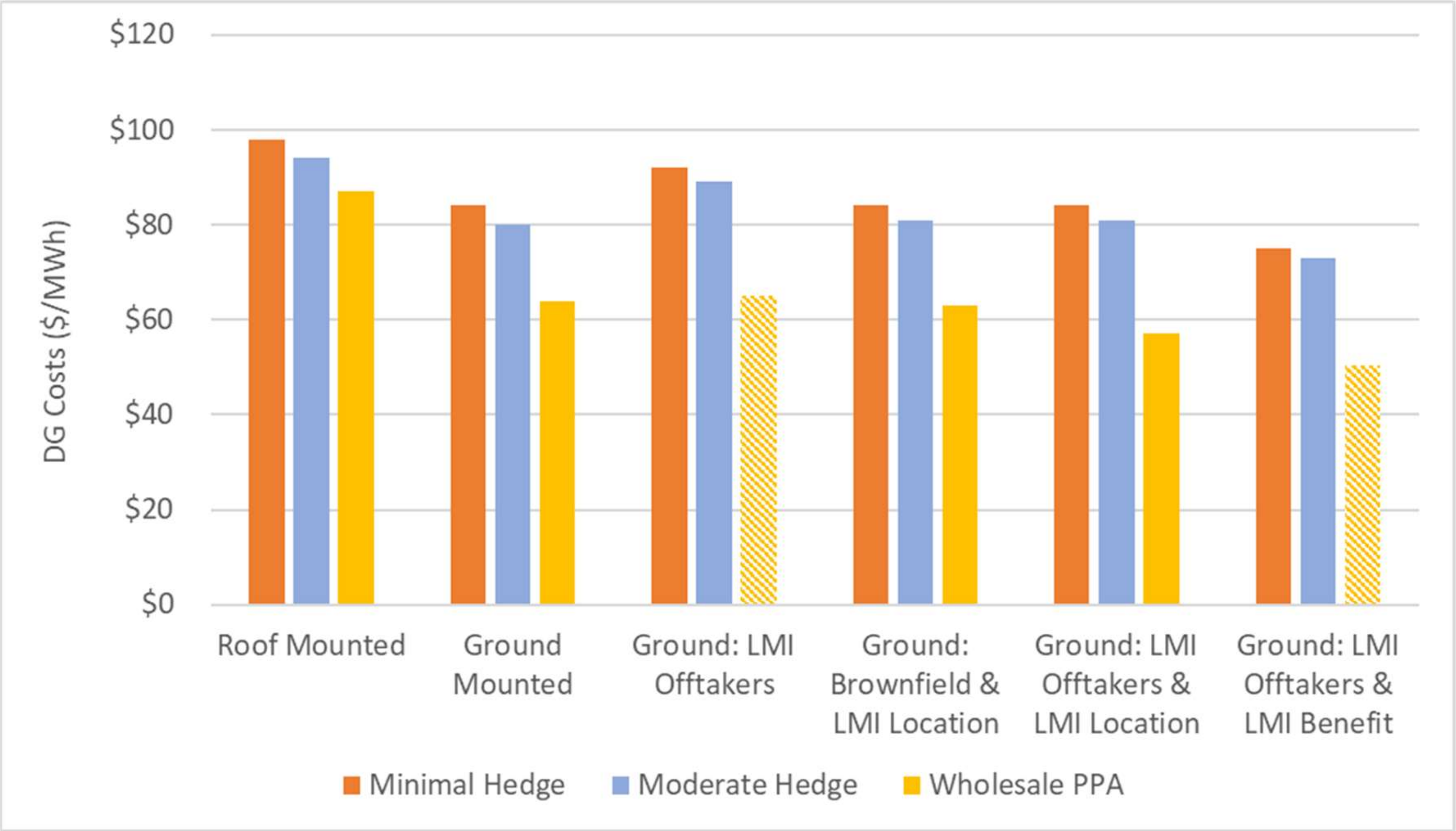
- The resulting MW allocation is then spread evenly across the resource blocks and five program years for the purposes of modeling (assuming a 3-year lag between selection and COD)
- In practice, Maine may want to implement non-uniform program allocations based on its policy goals (e.g., cost reduction, land preservation, equity)

Capacity targets for the successor program: results

- This method results in the following annual MW allocations by resource block
  - Note that, because Policy Option 4 (Wholesale PPA) would not allow for LMI offtake, resource blocks that require LMI offtake to qualify for ITC bonuses are not included for this Policy Option
  - Because Policy Option 4 allocates less MW to ground mounted under a uniform allocation across the available resource blocks, the average capacity factor is less than that of Policy Options 1-3, resulting in a marginally larger MW budget

	Program Options 1-3		Program Option 4	
	Annual	Cumulative	Annual	Cumulative
Large Commercial Roof Mounted	18.6	93	28.2	141
Large Ground Mount	18.6	93	28.2	141
Large Ground Mount (LMI offtakers)	18.6	93	not included	
Large Ground Mount (Brownfield/Other Energy Community)	18.6	93	28.2	141
Large Ground Mount (Located in LMI Community)	18.6	93	not included	
Large Ground Mount (LMI offtakers & Low-Income Benefit Project)	18.6	93	28.2	141
Total	111.6	558	112.8	564

Costs of DG resources: by resource block

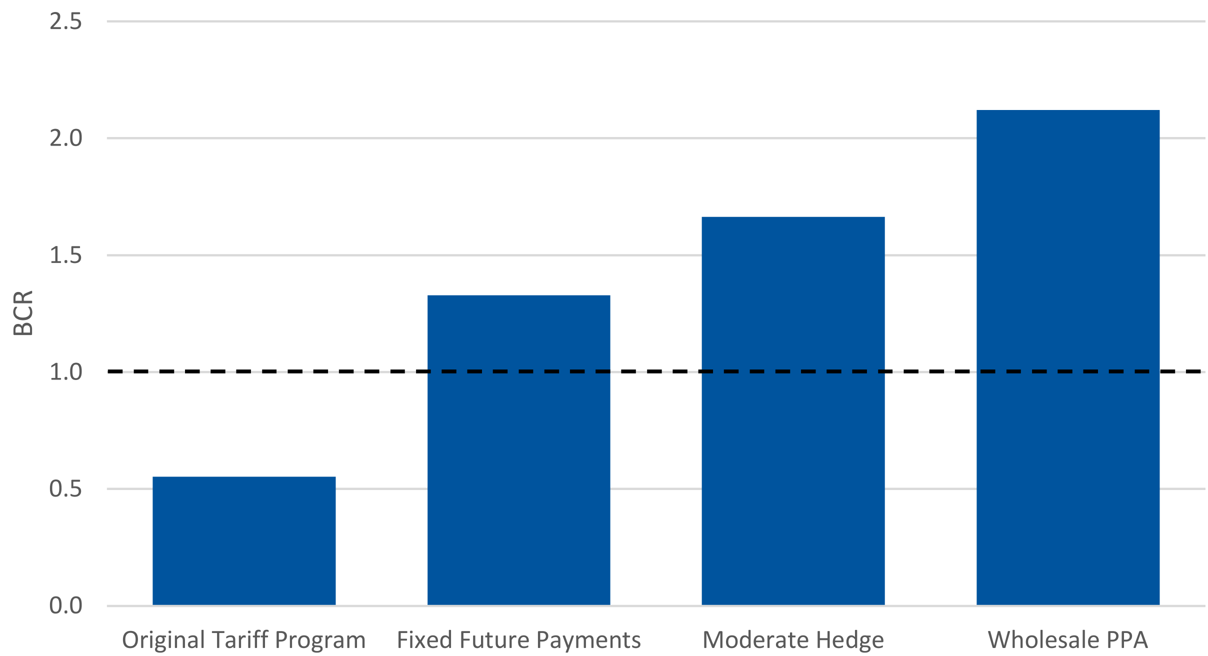


- The Original Tariff Program has the same costs in all cases.
- The yellow shaded bars indicate what the costs are for these blocks for the wholesale PPA program. These blocks are not included in our modeling because we are not certain that they will qualify for IRA benefits.

Benefit-Cost Analysis: Initial Results

BCA results: benefit-cost ratios

Program	BCR
1. Original Tariff Program	0.55
2. Fixed Future Payments	1.33
3. Moderate Hedge	1.66
4. Wholesale PPA	2.12



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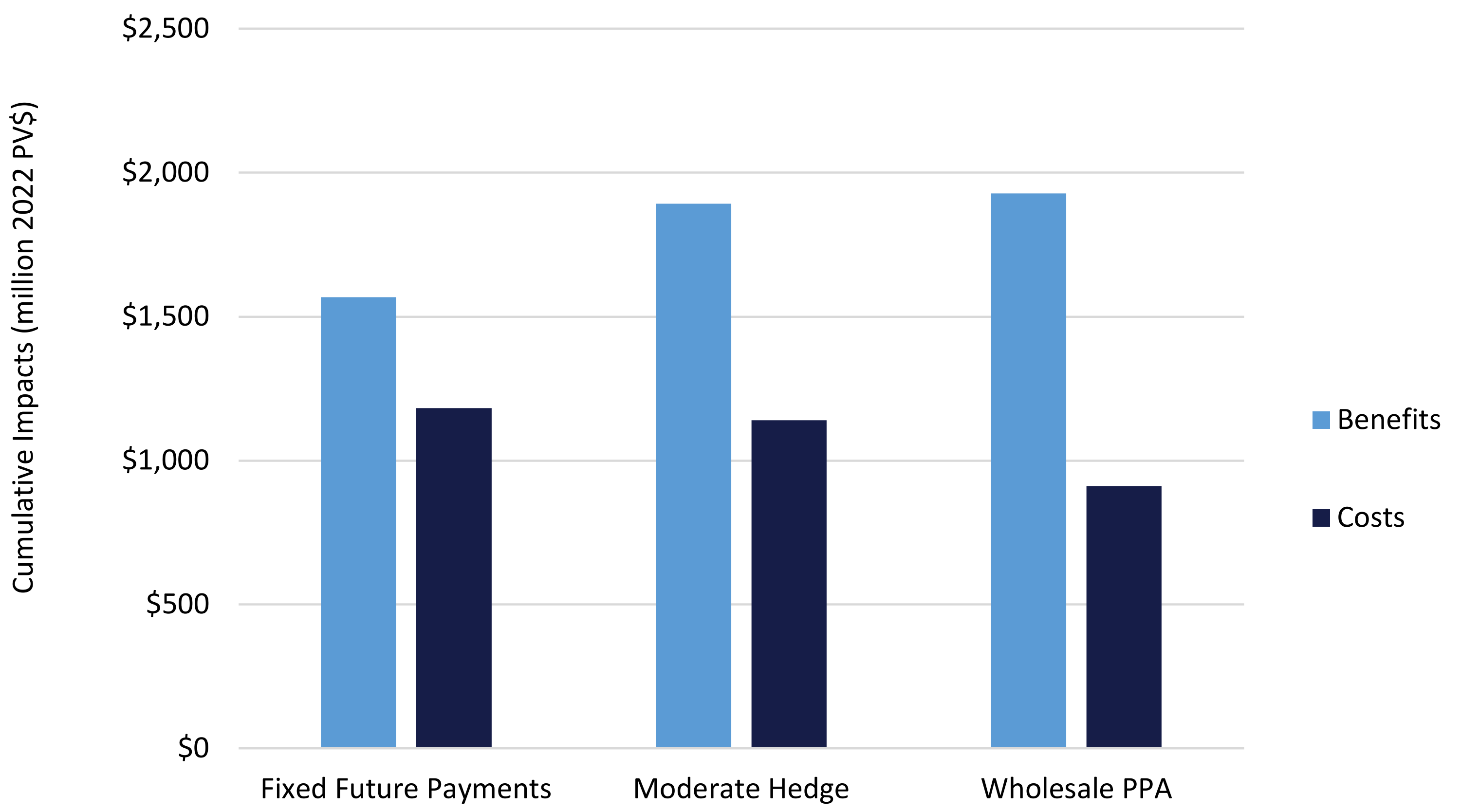
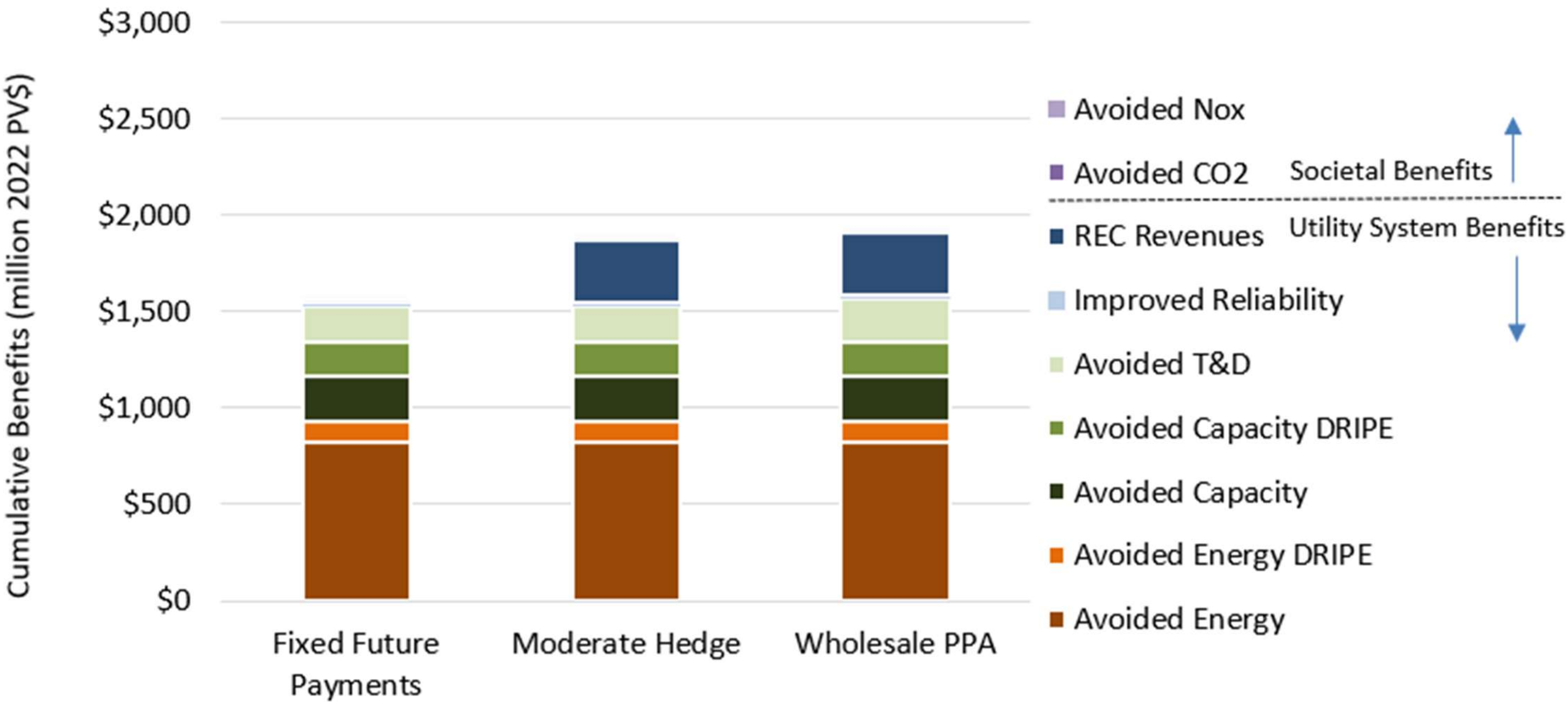
BCA results: benefits and costs



BCA results: benefits



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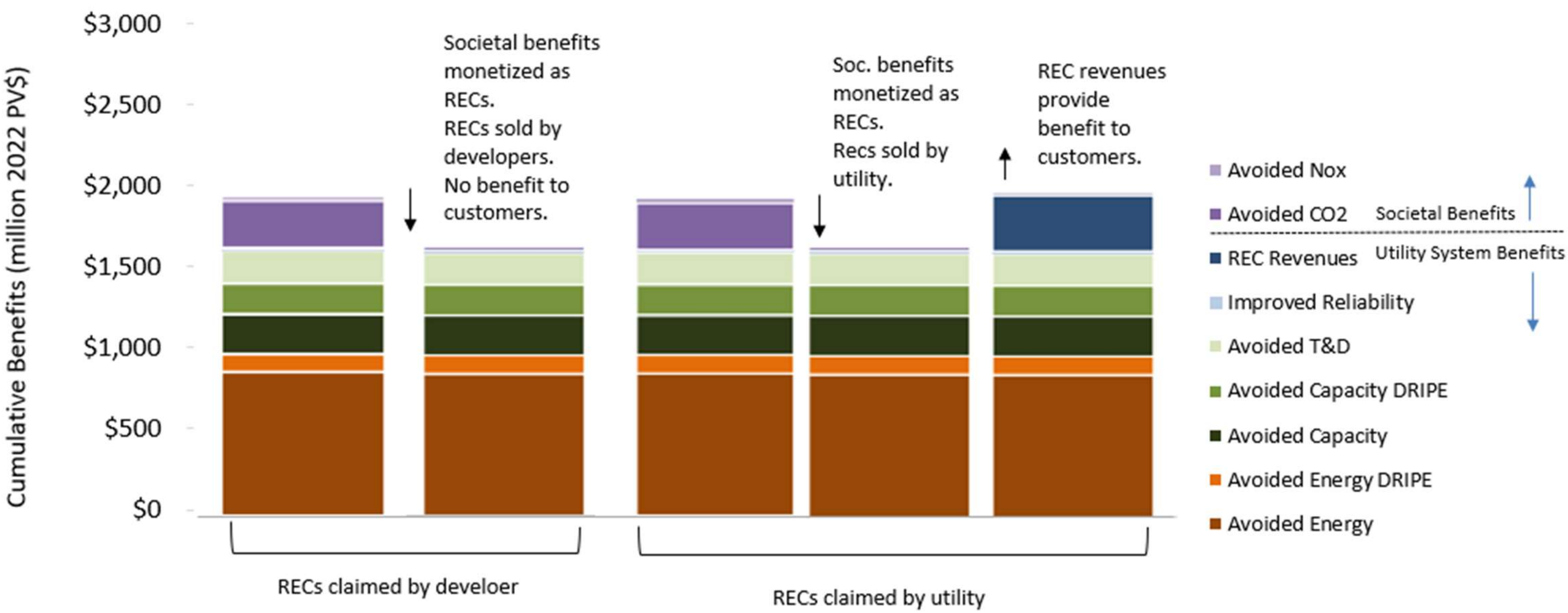
Societal benefits & REC interactions

- RECs are a mechanism for monetizing societal benefits
- Utilities can sell RECs to LSEs at the market price for RECs
- To avoid double counting, we reduce environmental benefits by the value of the RECs
- RECs that are sold by the utility become a utility system benefit rather than a societal benefit



Summary of BCA results

Re-instating a program like the Original Tariff Program would be a higher cost option than the successor programs modeled

- The starting payments are higher and
- The payments increase with increases in the electricity rates

Increasing the amount of hedging reduces the costs of DG

Assignment of RECs to the utility increases utility system benefits

- Because these RECs can be sold by the utility to get revenues

Alternatively, the DG RECs could be retired

- Which would lead to societal GHG benefits because other RECs would be needed to comply with the Maine RPS.
- In this case, the GHG benefits should be included in the BCA.
- But REC revenues should be removed from the BCA.
- Which means the overall BCA results do not change.
- But the rate impacts will be higher because of the loss of the REC revenues.

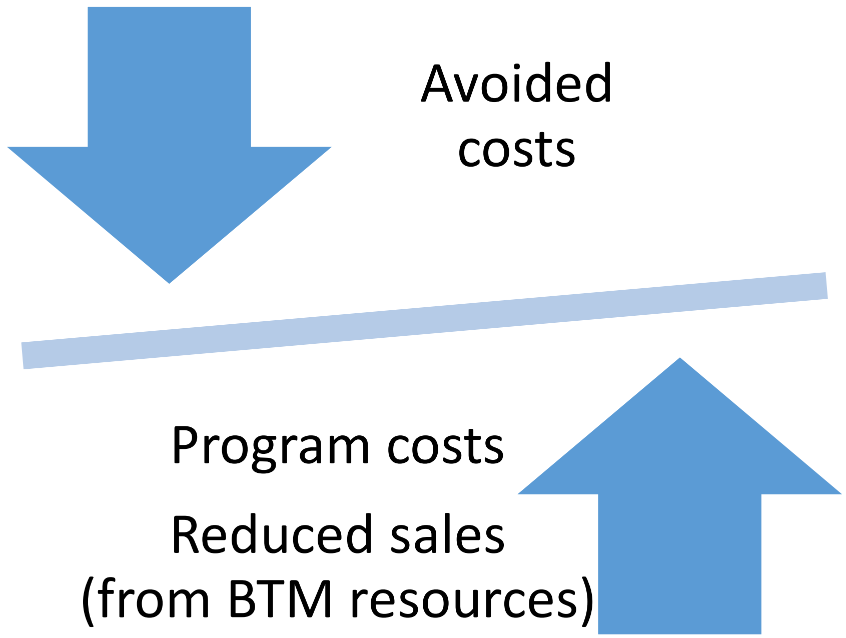
DG benefits that have not been monetized

- Low- and moderate-income customer benefits.
  - LMI participation is the same for each program option.
  - LMI participation varies by resource block.
  - LMI participation results are presented below.
- Resilience.
  - Resilience benefits are the same for each program option.
  - We expect the monetary values for these benefits to be very small.
- Participant non-energy benefits.
  - If there are any, they are the same for each program option.
  - Adding storage to the DG programs might increase participant non-energy benefits, such as reliability and resilience.
- Risk:
  - Risk benefits are the same for each program option.
  - Reduced risk of compliance with the RPS on a timely basis.

Rate Impact Analysis: Methodology and Assumptions

Rate impact methodology

- In general, program impacts translate into rate impacts in the following ways
  - Avoided costs resulting from the program exert downward pressure on rates
  - Program costs exert upward pressure on rates
  - Reduced sales (from behind-the-meter blocks) exert upward pressure on rates



Rate impact methodology – avoided costs

- We use four rates within our analysis: generation, transmission, distribution, other (includes all riders, stranded costs)
- Which avoided costs impact the **generation** rate?
  - Price suppression (DRIPE)
  - Reliability
  - REC revenue
- Which avoided costs impact the **transmission** rate?
  - Avoided PTF
  - Avoided Non-PTF transmission (BTM only)
- Which avoided costs impact the **distribution** rate?
  - Avoided Distribution (BTM only)
- Which avoided costs impact the **other** rate?
  - None

Rate impact methodology – other assumptions

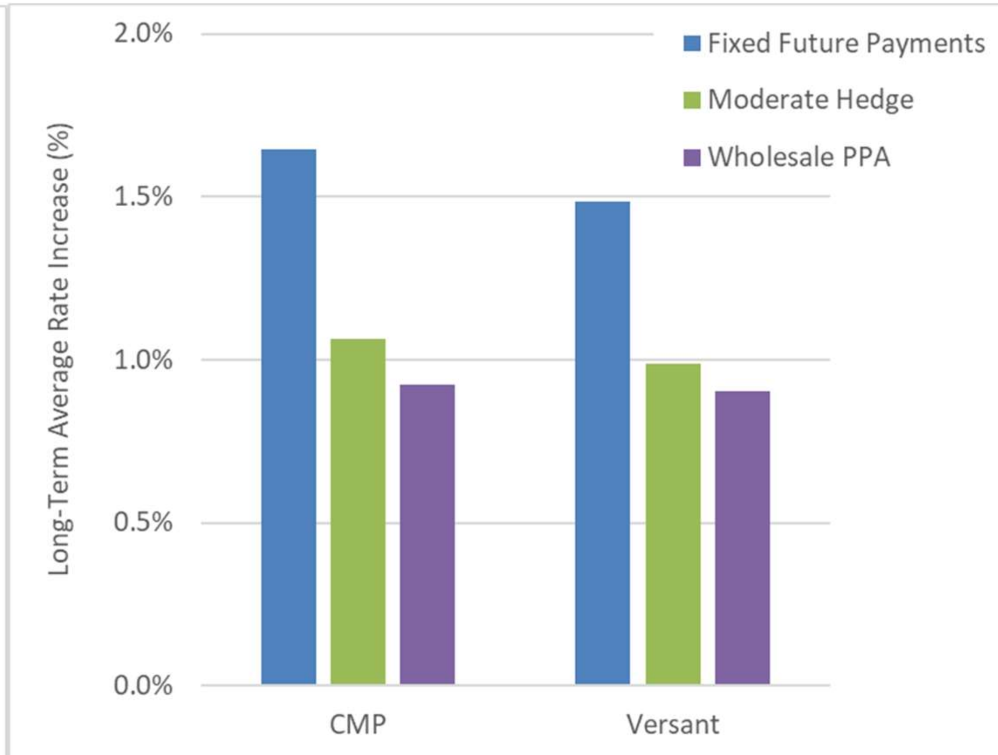
- Consistent base assumptions with BCA (discount rate, etc.)
- We use a **weighted average rate** (combining multiple rate classes) for each utility
- We use the state of Maine **load forecast** from the Maine Climate Council Forecast
- We distribute costs, benefits, and projected load based on 2021 EIA sales by utility:
  - CMP: 79%
  - Versant: 17%
  - Other: 4% (not included in our analysis)
- We also calculate the DG program charge, which includes the costs of the DG plus administration costs.
  - This does not reflect any of the benefits.

Rate Impact Analysis: Initial Results

Draft rate impacts: long-term averages

Rate Increase (¢/kWh)

Rate Increase (%)



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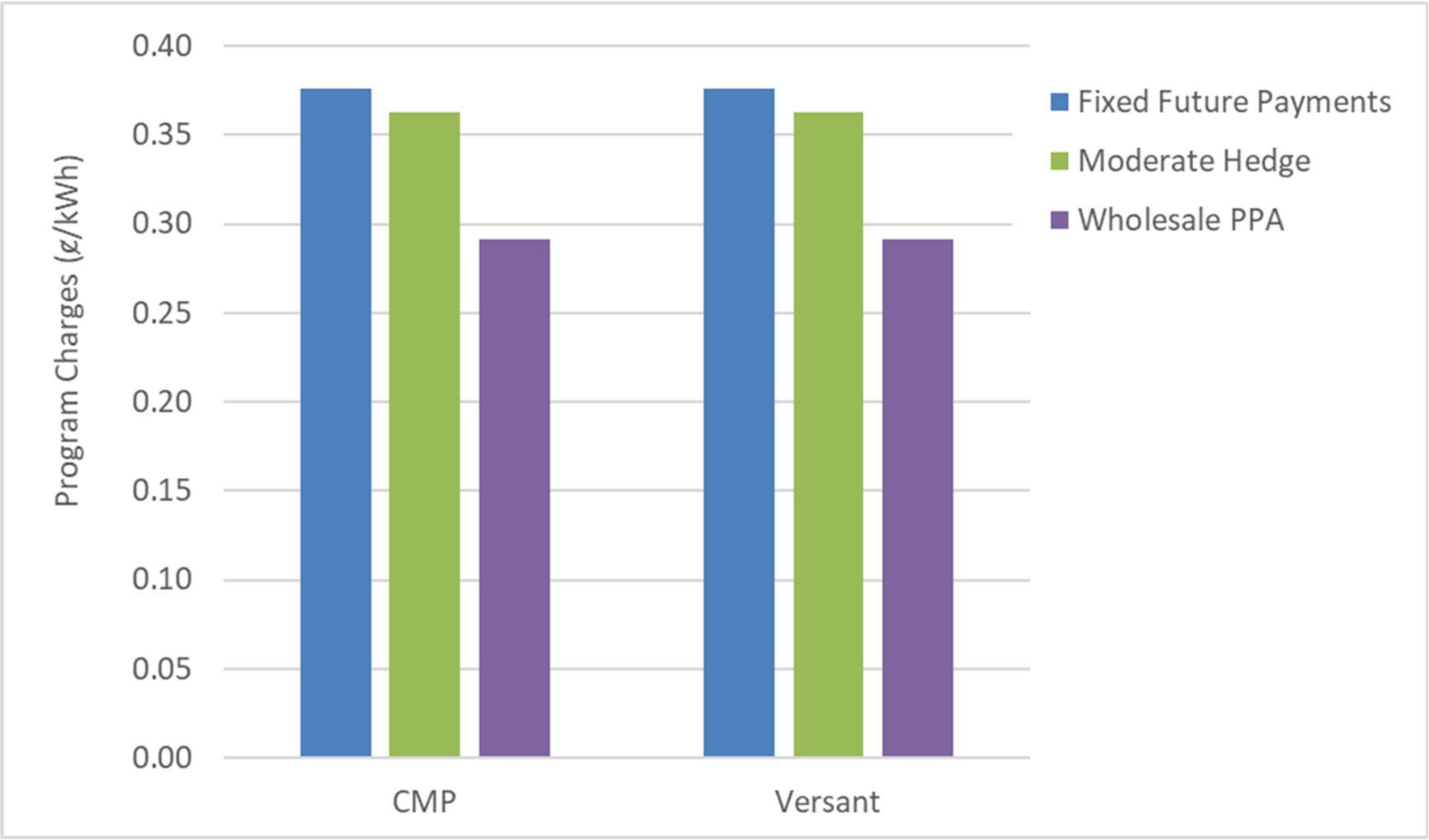
Draft program charges: long-term averages

The charges needed to recover the costs of the program.

- These charges do not reflect the downward pressure on rates from avoided costs.

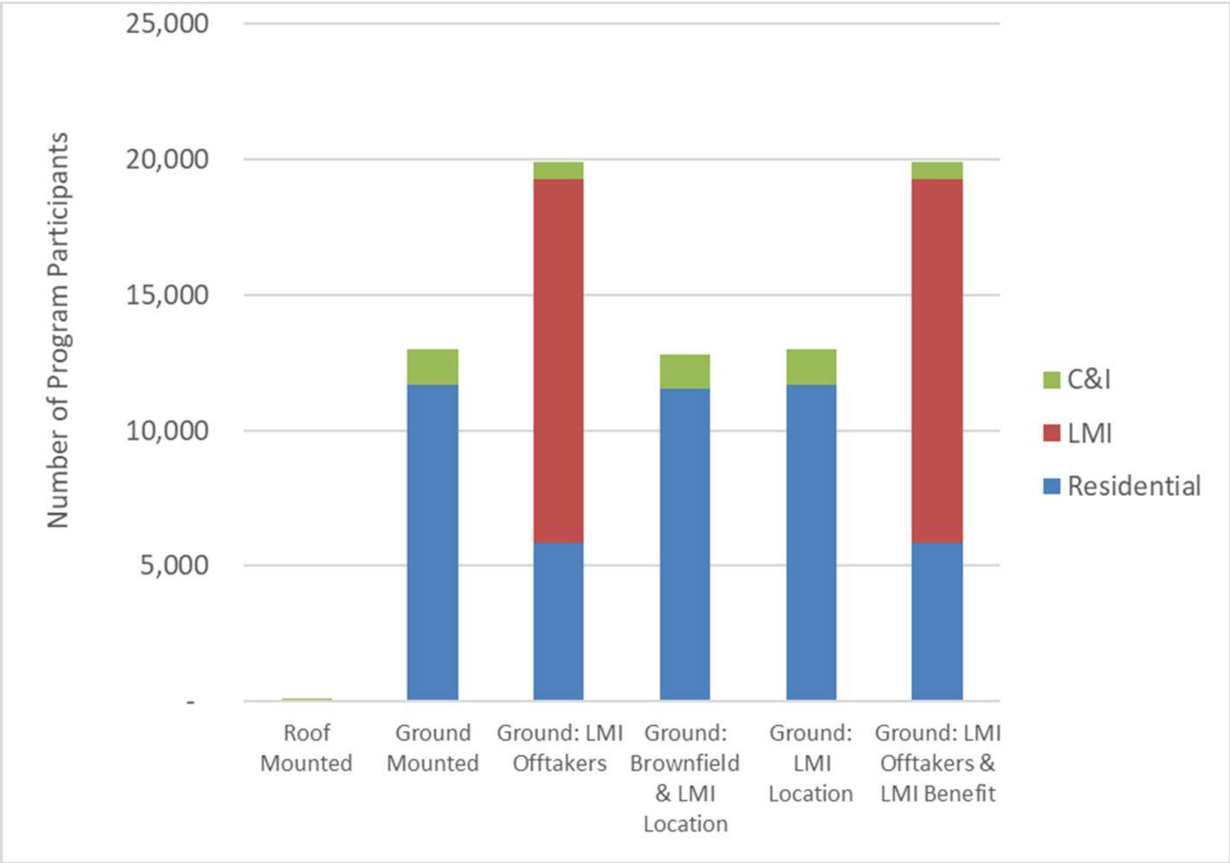


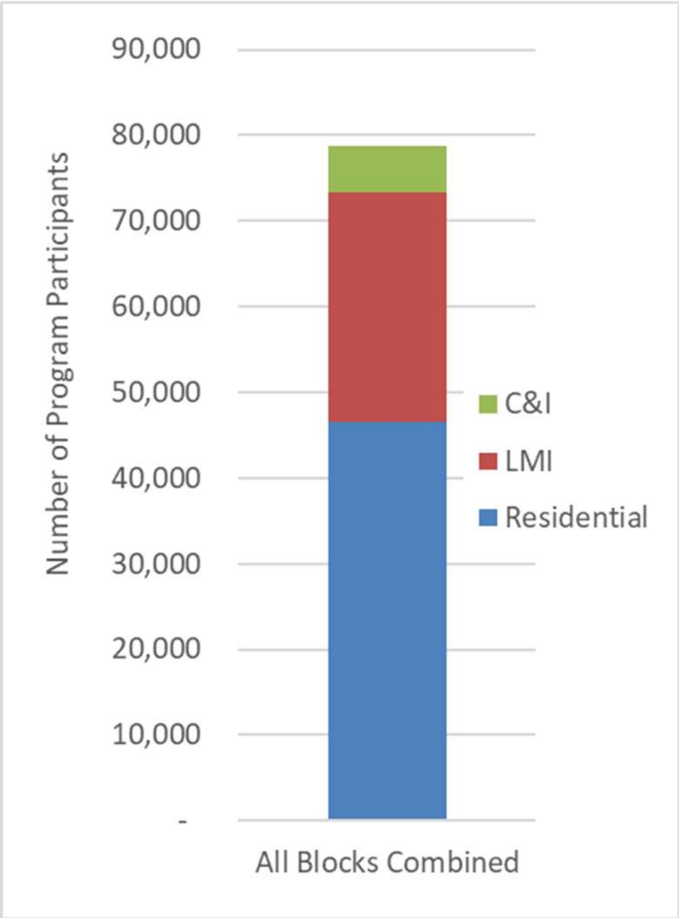
Summary of rate impact results

- The rate impacts follow the same pattern as the BCA results
- Rate impacts scale with program size
- After five years of DG implementation:
  - Annual energy produced = 859,210 GWh
    - This is roughly 6% of Maine electricity sales
  - Capacity installed = roughly 560 MW
    - This is roughly 25% of Maine peak demand
  - Program participants
    - Residential = 46,556 customers
    - LMI = 26,848 customers
    - C&I = 5,376 customers
    - Total = 78,779 customers (roughly 10% of customers)

Draft Participants

- Programs 1, 2, & 3 participants are presented in graphs below
- Program 4 has no participants, it affects all utility customers





Draft Bill Impacts: long-term averages

- Typical CMP residential customer
- Average change in monthly customer bill over program life

Program	Non-Participants		Participants	
	Bill Impacts		Bill Impacts	
	($/month)	(%)	($/month)	(%)
Fixed Future Payments	$1.87	1.6%	-$6.55	-5.7%
Moderate Hedge	$1.21	1.1%	-$7.22	-6.3%
Wholesale PPA	$1.05	0.9%	$1.05	0.9%

These are approximations. Impacts on any one customer will vary.

Straw Proposal, Sensitivities, & Next Steps

Straw proposal

- The straw proposal will be used for conducting sensitivities
- We recommend a hybrid of program options 3 and 4

Source Program	Technology	Location	Offtakers	IRA LMI Credit	Capacity
Program 3	Roof PV (1 MW)	BTM: Host customer	Host customer	none	84 MW
Program 4	Ground PV (5 MW)	FTM: anywhere	None (wholesale PPA)	none	131 MW
Program 4	~~Ground PV (5 MW)~~	~~FTM: anywhere~~	~~50% LMI, 25% Res, 25% C&I~~	~~10%~~	Not included
Program 4	Ground PV (5 MW)	FTM: Brownfield & LMI neighborhood	None (wholesale PPA)	10%	131 MW
Program 4	Ground PV (5 MW)	FTM: LMI neighborhood	None (wholesale PPA)	10%	131 MW
Program 3	Ground PV (5 MW)	FTM: LMI benefit	50% LMI, 25% Res, 25% C&I	20%	84 MW
-----	Totals	-----	-----	-----	560 MW

Forthcoming sensitivities

These sensitivities will be applied to the preferred program option.

1. Apply storage technologies to each resource block.
2. T&D impacts
   - Assume higher avoided T&D costs. Suggestions welcome
   - Assume lower avoided T&D costs. Suggestions welcome
3. Increase or reduce diversity by altering resource blocks.
   - Suggestions for other options welcome
4. Higher or lower discount rates.
   - Suggestions for alternative discount rates welcome

Next Steps

- DG Workgroup meeting on November 22
  - To discuss the DG technology cost inputs to the BCA
  - To continue any issues remaining from today's meeting
- DG Workgroup meeting on December 6
  - To discuss final BCA and rate impact results
  - To discuss results of sensitivities

Acronyms

Benefit-Cost Analysis (BCA)

Behind-the-Meter (BTM)

Commercial & Industrial (C&I)

Cost of Renewable Energy Spreadsheet Tool (CREST)

Front-of-the-Meter (FTM)

Maine Governor's Energy Office (GEO)

Inflation Reduction Act (IRA)

Low-Moderate Income (LMI)

Net Energy Billing (NEB)

Power Purchase Agreement (PPA)

Residential (Res)

Renewable Energy Certificates (RECs)

Sustainable Energy Advantage (SEA)

To be Determined (TBD)

Time-of-Use (TOU)