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Rhode Island Energy™
a PPL company

March 30, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-49-EL-The Narragansett Electric Company d/b/a Rhode Island Energy Advanced Metering Functionality Business Case
Responses to Division Data Requests – Division Set 3

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), attached is the electronic version of Rhode Island Energy's responses to the Division of Public Utilities & Carriers' (the "Division") Third Set of Data Requests in the above-referenced matter.[1]

Thank you for your time and attention to this matter. If you have any questions, please contact Jennifer Brooks Hutchinson at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Jennifer Brooks Hutchinson

Enclosures

cc: Docket No. 22-49-EL Service List
John Bell, Division
Leo Wold, Esq.

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[1] Per communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by hard copies filed with the Clerk within 24 hours of the electronic filing.

CERTIFICATE OF SERVICE

I certify that a copy of the within documents was forwarded by e-mail to the Service List in the above docket on the 30th day of March, 2023.

Adam M. Ramos, Esq.

The Narragansett Electric Company d/b/a Rhode Island Energy
Docket No. 22-49-EL Advanced Meter Functionality (AMF)
Service list updated 2/27/2023

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Division 3-1

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Prior to and after PPL implementing AMF in Pennsylvania, what methods were made available for customers to report an outage (phone call, website, text, etc.)? How were these alternative methods of notification used in addition to phone calls when tracking the time difference? If alternative methods were not considered, explain why.

Response:

PPL Electric Utilities Corporation's customers in Pennsylvania are able to report an outage through the following channels: the website, through the Interactive Voice Recognition system, talking to a customer service agent directly, and text. Each of these outage reporting channels were in existence prior to the implementation of advanced metering infrastructure ("AMI") in Pennsylvania, with the exception of text, and have continued. The ability for customers to text an outage went into production June of 2018. Each of these channels to report an outage is tracked in the same way, updating the customer contact in the customer information system ("CIS") and flowing into the outage management system ("OMS") to create an outage ticket. All of these reporting methods were considered in the same way and counted and generalized as a "customer call" in the analysis that was completed.

Division 3-2

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

In tracking the time difference, did PPL rely only on calls where customers initially report an outage or would calls for other reasons be included, such as questions on restoration time, providing information on a downed line, etc.? How did PPL differentiate the calls?

Response:

PPL used the first outage report (via call, IVR, web, or text) received from a customer affected by an outage. The outage reports are differentiated by using the initial outage report only and do not include customer follow-ups or downed lines, for example. Additionally, the data set also included a corresponding last gasp notification.

Prepared by or under the supervision of: Philip J. Walnock

Division 3-3

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

In deriving the 22 minute faster notification time, how did PPL take into account the customer tendency to call in an outage that was likely different pre-AMF? For instance, wouldn't customers be more likely to make a call, and make it sooner in a pre-AMF scenario when they knew that outages were not automatically reported?

Response:

PPL Electric Utilities Corporation ("PPL Electric") does not have specific data to quantify the likelihood of customers to call in an outage comparing before and after advanced metering infrastructure ("AMI") implementation. The time frame chosen for the analysis in the benefit-cost analysis ("BCA") was August 2019 through July 2020. This timeframe was selected because in August 2019, PPL Electric had completed most of the meter exchanges and Last Gasp meter alert functionality was fully implemented, making it the best period to measure the difference in notification time since customer-initiated call behavior could change over time. Additionally, from August 2019 through July 2020, PPL Electric was able to restore approximately 19% of outages without receiving a contact from a customer based on Last Gasp meter alerts alone. In the two years after that beginning in August 2020 through July 2022 that number has increased to approximately 25%.

Prepared by or under the supervision of: Flora Flygt, Wanda Reder, and Philip J. Walnock

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Division 3-4

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Discuss how PPL used outage management system data to derive the 22 minute faster notification time in terms of time stamping the meter "Last Gasp" and customer calls. Is PPL tracking the time between the "Last Gasp" and first customer call to report an outage or does the data set include all customer calls related to the same outage? If the latter, how does PPL consider which customer calls should be considered in determining the faster restoration time as opposed to customer calls that occurred later for the same outage and were only redundant? For instance, consider a case where a fuse blows on a tap line serving 50 customers and five customers call within five minutes, providing the utility with enough granular information to determine that a tap line fuse has blown. If ten additional customers call thirty minutes later to report the outage, would PPL include all calls in the data set or only the first five calls?

Response:

PPL Electric Utilities Corporation used a dataset that captured both customer-initiated outage notifications and advanced metering infrastructure ("AMI") meter Last Gasp notification to derive the 22-minute faster notification. As explained in the Company's response to PUC 5-8, the faster outage notification was calculated for outages where both Last Gasp meter alerts and customer-initiated outage notifications were received into the outage management system ("OMS"). The calculation uses the variance between the timestamp in OMS indicating when the outage number ticket was created upon receiving Last Gasp meter alerts and the timestamp for the first customer-initiated report of an outage sent to OMS from the customer information system. The 22-minute faster outage notification is a result of taking the simple average of the time variance between the outage ticket creation and the first customer report of an outage for all outages in the dataset.

The dataset does not include all customer calls for each outage; instead, the dataset only includes the first customer-initiated report of the outage.

For the example in the request of a blown fuse serving 50 customers, the dataset would include only the first customer-initiated report out of the 15 calls used in the example. The interpretation of using the first customer-initiated call compared to Last Gasp is the most conservative interpretation of the difference in outage notification time between the AMF Last Gasp and customer-initiated reporting. In reality, the time it takes to pinpoint an outage with customer-initiated calls is usually longer and more involved than simply logging the first customer call because operators would need to analyze multiple customer calls determine the point of common failure.

Prepared by or under the supervision of: Philip J. Walnock and Wanda Reder

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Division 3-5

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Where PPL is tracking the time difference between when they are notified of the outage and when the customer calls in, explain how the utility determines when it is *notified of the outage*. Is this notification limited to outages detected solely by an AMF meter or would it include outages that were also detected by other system devices that are integrated into the outage management system? In general, would PPL agree that only outages relying solely on AMF meter notification should be used in the data set to track the time difference relied upon to determine the benefit of AMF? If so, discuss how PPL screened and separated outages relying solely on AMF notification from all other outages. If not, explain why outages where the utility received notification from other systems, in lieu of or in addition to AMF notification, should be included in the data set.

Response:

As outlined in the Company's response to PUC 5-8, the difference between a customer-initiated outage notification and an AMF meter last gasp notification is as follows:

- A customer-initiated outage is when a customer contacts the Company via a call, web entry, the IVR, or text, alerting the Company they are experiencing an outage. The time stamp for the measure is when the customer outage initiation time is captured in the Customer Information System.
- An AMF meter Last Gasp notification is when the meter receives the last gasp alert for loss of service. The time stamp for the measure is when the Last Gasp notification creates an outage ticket in the Outage Management System.

Only outages that included both an AMF meter Last Gasp notification and a customer-initiated call were included in the dataset to determine the faster outage notification benefit for AMF.

Prepared by or under the supervision of: Philip J. Walnock and Wanda Reder

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Division 3-6

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

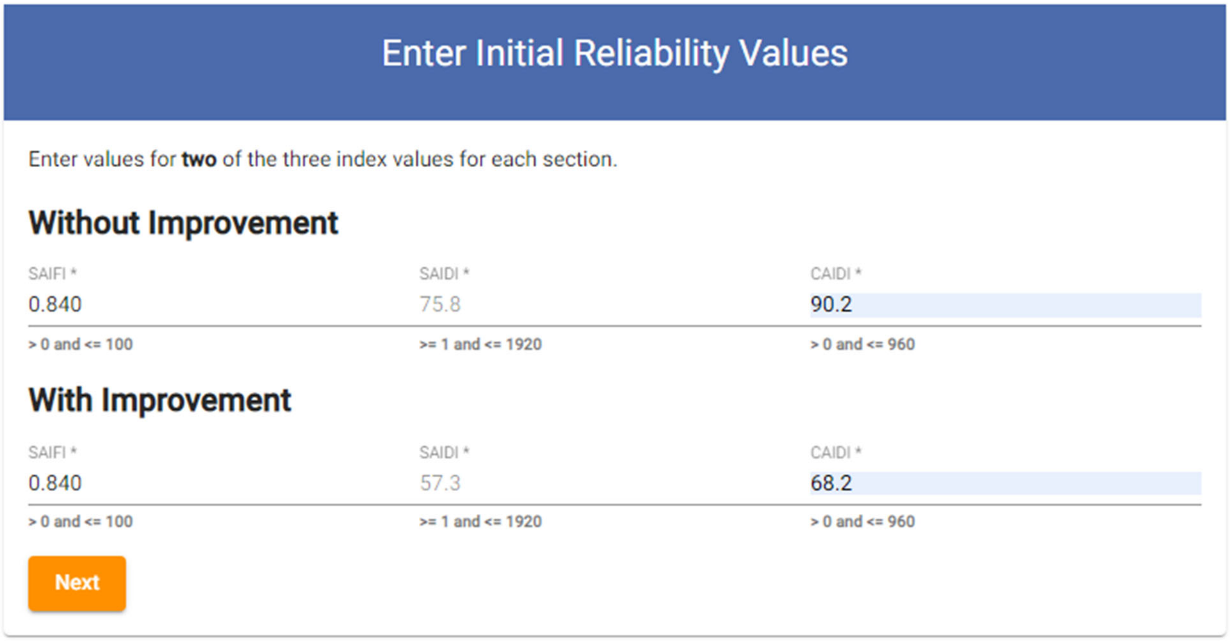
Request:

If the 22 minutes are not included in utility reliability statistics, how does the Company input the data into the ICE Calculator model to determine the impact of faster outage notification?

Response:

There are three inputs to the ICE calculator when determining with and without improvement reliability values: SAIFI, SAIDI and CAIDI. The instructions show that you must enter values for two of the three index values for each section. Because these 22 minutes impacts the customer experience, the Company decided to use an adjusted CAIDI value in the ICE calculator to determine the dollar value impact the 22-minute faster notification would provide as a benefit. Therefore, the Company added the 22-minutes to Rhode Island Energy's CAIDI value to input the data into the ICE calculator. The CAIDI value that was used in the calculation is 68.2, which is the 3-year average CAIDI value for Rhode Island Energy from 2018-2020. This value was input to the "With Reliability Improvement" CAIDI and 90.2 was input to the "Without Reliability Improvement" CAIDI. The second input used was SAIFI. The SAIFI used was determined by calculating rolling five-year averages using data from 2005 through 2020 and choosing the lowest value, which was 0.84. This was done to be conservative in the estimates.

Below is a screen shot showing the data as it was input to the ICE Calculator.



Enter Initial Reliability Values

Enter values for **two** of the three index values for each section.

Without Improvement

SAIFI * 0.840 (> 0 and <= 100)
SAIDI * 75.8 (>= 1 and <= 1920)
CAIDI * 90.2 (> 0 and <= 960)

With Improvement

SAIFI * 0.840 (> 0 and <= 100)
SAIDI * 57.3 (>= 1 and <= 1920)
CAIDI * 68.2 (> 0 and <= 960)

Division 3-7

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

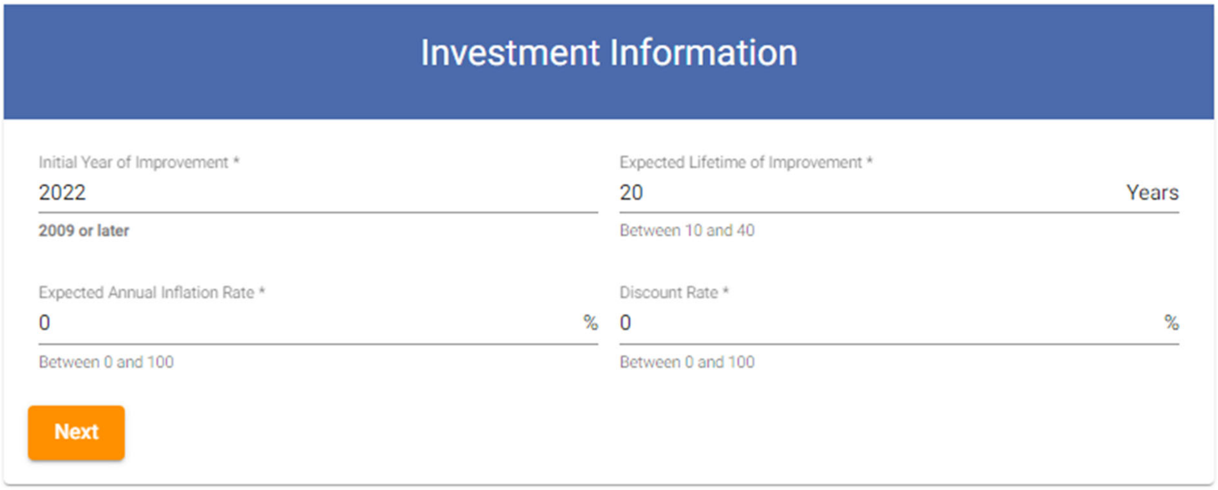
Request:

The ICE Calculator appears to deliver results for customer outage estimated costs in 2016 dollars. How did the Company adjust these findings to get to 2022 dollars?

Response:

The ICE calculator requests, as inputs, Investment Information, including the year of the improvement, the life of the improvement, the inflation rate and the discount rate. The Company input 2022 as the year of the improvement, 20 years for the lifetime, and 0% for both the inflation rate and the discount rate. Zero percent was used for the inflation and the discount rates because the Company was inflating and discounting values directly in the BCA model. Because the Company put in a zero discount rate, the values were labeled $2022 but were actually $2016. This would make the estimate more conservative than if the $2016 were inflated to $2022.

Below are screen shots showing the inputs to and outputs from the ICE calculator.



Investment Information

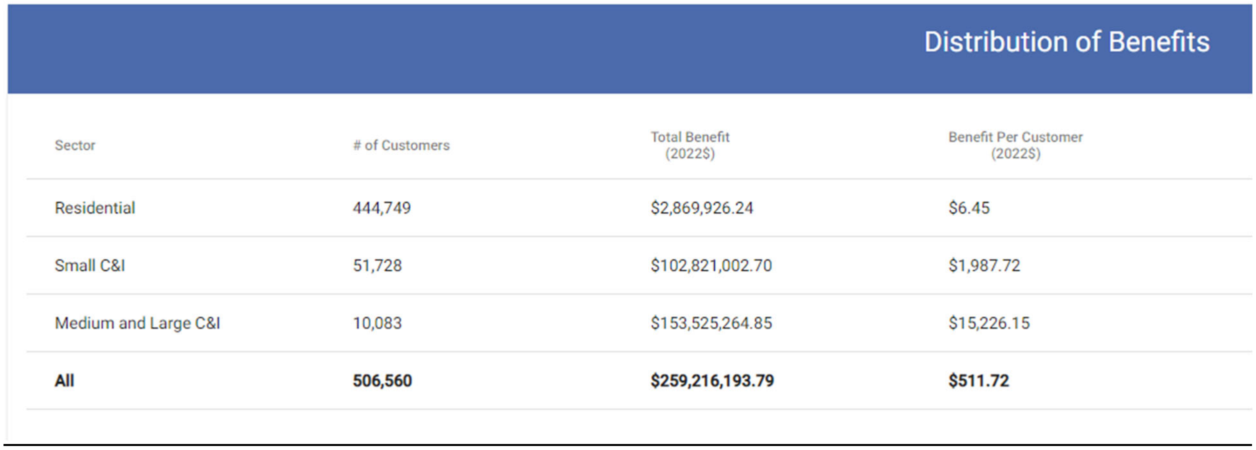
Initial Year of Improvement *
2022
2009 or later

Expected Lifetime of Improvement *
20 Years
Between 10 and 40

Expected Annual Inflation Rate *
0 %
Between 0 and 100

Discount Rate *
0 %
Between 0 and 100

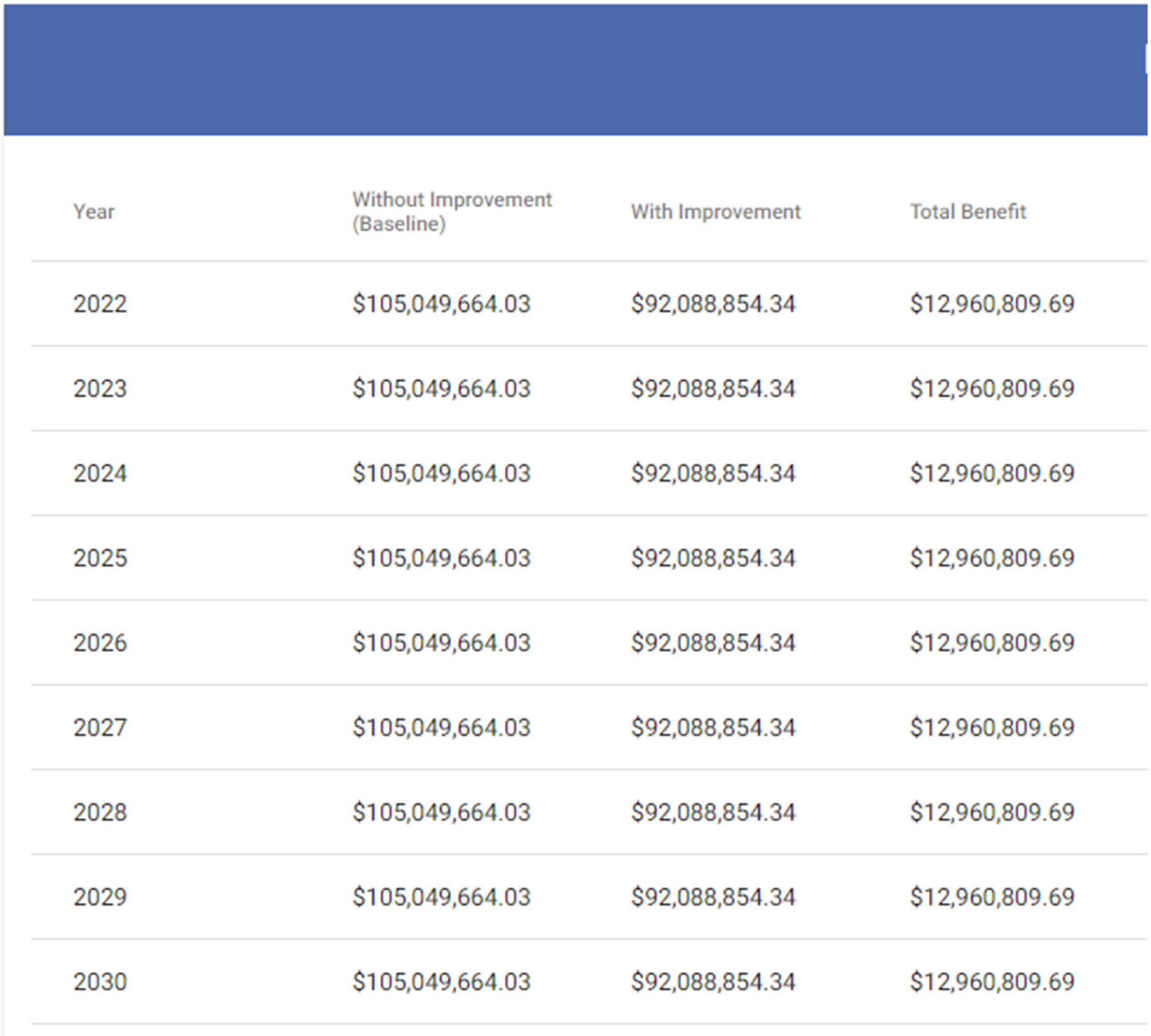
Prepared by or under the supervision of: Wanda Reder and Flora Flygt



Distribution of Benefits

Sector	# of Customers	Total Benefit (2022$)	Benefit Per Customer (2022$)
Residential	444,749	$2,869,926.24	$6.45
Small C&I	51,728	$102,821,002.70	$1,987.72
Medium and Large C&I	10,083	$153,525,264.85	$15,226.15
All	**506,560**	**$259,216,193.79**	**$511.72**

Prepared by or under the supervision of: Wanda Reder and Flora Flygt



Year	Without Improvement (Baseline)	With Improvement	Total Benefit
2022	$105,049,664.03	$92,088,854.34	$12,960,809.69
2023	$105,049,664.03	$92,088,854.34	$12,960,809.69
2024	$105,049,664.03	$92,088,854.34	$12,960,809.69
2025	$105,049,664.03	$92,088,854.34	$12,960,809.69
2026	$105,049,664.03	$92,088,854.34	$12,960,809.69
2027	$105,049,664.03	$92,088,854.34	$12,960,809.69
2028	$105,049,664.03	$92,088,854.34	$12,960,809.69
2029	$105,049,664.03	$92,088,854.34	$12,960,809.69
2030	$105,049,664.03	$92,088,854.34	$12,960,809.69

Division 3-8

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Do RIE customers currently inform the utility of outages by means other than a phone call such as internet or text?

Response:

Yes. Rhode Island Energy customers currently can report power outages through the interactive voice response ("IVR"), website, speaking with a customer service representative, or through a text message.

Division 3-9

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Do RIE and prior National Grid customer notifications reporting an outage automatically propagate the outage management system? Would this occur with all available methods of notification (calls, internet, etc.)?

Response:

Rhode Island Energy and prior National Grid customer notifications can be reported through the IVR, website, speaking with a customer service representative, or through a text message. Once the outage report is completed in any of those systems, it is automatically sent to the Outage Management System.

Prepared by or under the supervision of: Wanda Reder and Philip J. Walnock

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Division 3-10

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

For the previous five years, provide the number of customer outage notifications received by RIE, broken out by the method of notification (phone call, internet, etc.). Provide the same information for PPL.

Response:

Rhode Island Energy customers can notify the company of an outage by way of the Interactive Voice Response system ("IVR"), calling and speaking to an agent, SMS text or through the web. The number of notifications by type for the previous five years is summarized in the table below.

Year	IVR	Phone	SMS text	Web	Grand Total
2018	29,472	119,942	--	84,331	233,745
2019	25,743	59,772	5,569	72,262	163,346
2020	49,594	70,285	25,939	95,110	240,928
2021	10,346	73,350	48,986	60,509	193,191
2022	7,954	43,199	23,511	33,229	107,893

PPL Electric Utilities Corporation customers in Pennsylvania can notify the company of an outage by way of the IVR, calling and speaking to an agent, SMS text or through the web. The requested data is not available for dates before April 2019. Data from April 2019 thru December 2022 summarizing the type of notification is provided by year in the table below.

Month	IVR	Phone	SMS text	Web	Grand Total
2019-04 to 12	154,480	92,131	39,915	58,720	345,246
2020-01 to 12	131,604	94,841	60,179	66,598	353,222
2021-01 to 12	38,237	87,383	40,651	128,579	294,850
2022-01 to 12	65,492	81,971	34,266	261,798	443,527

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Division 3-11

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Does RIE currently send a text, email or other automatic communications to customers affected by an outage that the power is out? Does this notification include an estimated restoration time? If not, explain why not. Is this service opt-in or opt-out? What percentage of customers are enrolled? Discuss current methods of automated outage notifications to customers and any changes that would be implemented with AMF deployment.

Response:

Rhode Island Energy currently sends outage notifications to customers who are enrolled to receive them. If an estimated restoration time is available in the Outage Management System, it will be included in the notification that is sent to the customer. Enrollments have occurred by opt-in upon completion of an online profile, and there also was an auto enrollment process completed within the past two years. Customers also can opt out at any time or mute the messages. The outage notifications can be performed through email, text, and/or voice massages, depending upon customer choice. The AMF deployment will not change the way that enrolled customers are notified of outages affecting them. The table below provides the number and percentage of customers who receive each type of outage notification.

Outage Notification Type	# of Customers	% of Customers
Text	227,765	45%
Email	339,901	68%
Voice	725	0.14%

Prepared by or under the supervision of: Philip J. Walnock

Division 3-12

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Does PPL send a text, email or other automatic communications to customers affected by an outage that the power is out? Does this notification include an estimated restoration time? If not, explain why not. Is this service opt-in or opt-out? What percentage of customers are enrolled?

Response:

The practice of sending email and voice outage notifications to customers has been in place in Pennsylvania since 2011 with text notifications added in 2018. Enrollments have been accomplished through opt in and auto enrollment. Multiple message types are used (Initial Outage Notification, Updates, Restoration) and each message has variations based upon the scenario. In general, the messages contain the following information:

- Identification of PPL as the caller with a call back number provided
- Notification of an outage in the customer's area
- Estimated restoration time (if available)
- Estimated # of customers affected by the outage
- Status of restoration efforts (if available)
- Cause of outage (if available)
- How to get more information
- Safety warning to stay away from downed wires

As of 03/16/2023, there are a total of 1,087,448 active accounts in Pennsylvania who are enrolled to receive outage notifications. This represents 74.1% of the current active accounts.

Prepared by or under the supervision of: Philip J. Walnock

Division 3-13

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Does RIE currently depend on customer notification for all outages or are there other methods to determine that an outage has occurred? Do any of the protective devices automatically notify of an outage such as a substation breaker lockout being recorded by the SCADA system and reported as an outage through the outage management system?

Response:

Rhode Island Energy primarily relies on customer notification for outages. Rhode Island Energy does have SCADA notification for most circuit breakers as well as Pole Top Reclosers where the operation of these devices can provide notification to Rhode Island Energy of an outage. These are not directly integrated into the Outage Management System and rely on a System Operator noting the operation of the device in one system and manually updating it in the Outage Management System.

Prepared by or under the supervision of: Philip J. Walnock and Wanda Reder

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Division 3-14

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Currently, do any RIE meters interface with utility systems to provide the Company with notification when the customer experiences an outage? If so, what types or class of customers have this meter functionality and how many meters are installed?

Response:

No, there are currently no Rhode Island Energy meters installed that provide notification to the Company that the customer has experienced an outage.

Division 3-15

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

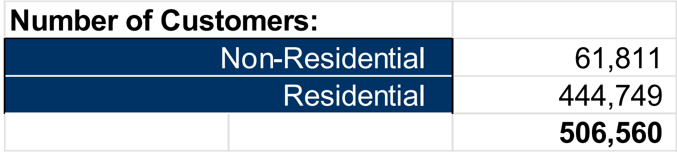
How did RIE estimate the type of customer impacted by an outage to use in the ICE calculation?

Response:

The ICE calculator used for the benefit-cost analysis ("BCA") takes two inputs: residential and non-residential customer counts. Using the input total, the model then generates three outputs: residential, small C&I, and medium and large C&I populations. The ICE calculator includes an algorithm that splits the input for non-residential customers into small C&I customers and medium and large C&I customers. Rhode Island Energy customer count totals for residential and non-residential as of March 2022 were input into the ICE calculator.

Because the ICE calculator did not split the non-residential customer counts correctly between small and large C&I customers, an adjustment had to be made to match the actual Rhode Island non-residential customer counts. Below are the calculations and screen shots of the inputs used to develop the Faster Notification benefit and the outputs from the ICE calculator. Also included are the adjustments made to reflect actual Rhode Island Energy small C&I and large C&I customers.

ICE Calculator Customer Input:



Number of Customers:	
Non-Residential	61,811
Residential	444,749
	506,560

ICE Calculator Output

Distribution of Benefits:

Sector	No. of Customers	Total Benefit (2022$)	Benefit per Customer (2022$)
Medium and Large C&I	10,083	$153,525,250.8	$15,226.1
Small C&I	51,728	$102,820,985.6	$1,987.7
Residential	444,749	$2,869,926.0	$6.5
All	**506,560**	**$259,216,162.4**	**$511.7**

Customer Count Adjustment:

The number of customers from the ICE calculator output for Medium and Large C&I was adjusted from 10,083 to the Rhode Island Energy actual count of Medium and Large C&I of 8,469. The number of customers from the ICE calculator output for Small C&I was adjusted from 51,728 to the Rhode Island Energy actual count of Medium and Large C&I of 53,342. The benefit per customer remained the same and the adjusted customer count reflected a new Benefit total shown below.

Distribution of Benefits:

Sector	No. of Customers	Total Benefit (2022$)	Benefit per Customer (2022$)
Medium and Large C&I	8,469	$128,950,247.9	$15,226.1
Small C&I	53,342	$106,029,172.1	$1,987.7
Residential	444,749	$2,869,926.0	$6.5
All	**506,560**	**$237,849,345.9**	**$511.7**

From this adjustment, the Company divided the total benefit into 20 years to get an average benefit per year of $11,892,467.30 million.

This per year benefit was then used in the BCA calculation as the annual benefit starting at year 1 (2022), inflated at 2% per year with the actual benefit beginning to accrue in year 2025 at 50% and accruing at 100% per year beginning in 2026 through 2041, resulting in a final benefit of $243.79 million.

This response is consistent with the Company's response to PUC 5-16.

Prepared by or under the supervision of: Wanda Reder and Flora Flygt

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Division 3-16

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Given that RIE follows a fuse sacrifice philosophy, when RIE receives notification of an outage from a system device, is the Company currently able to determine the affected customers? Why or why not? How would outage notification from AMF improve the restoration time in this case?

Response:

When a fuse operates, it will cause an outage for those customers served behind it. Currently, Rhode Island Energy depends upon customer-initiated calls to be notified of the outage to the affected customers for fuse operations. With advanced metering functionality ("AMF"), the Company will consider itself notified of the outage when it receives "Last Gasp"[1] notification at which time an outage is logged and time stamped in the Outage Management System ("OMS"). Last Gasp outage notification improves the notification time required to define and enter the outage into OMS because each AMF meter sends an electronic notification that power is out for each customer that is affected by the outage. This alerts system operators at the time an outage has occurred, rather than waiting for customer-initiated calls to notify Rhode Island Energy that they are out of power. The AMF Business Case included a 22-minute average improvement in outage notification time because of the Last Gasp capability, which was quantified by the ICE calculator. See the Company's response to Division 1-5.

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[1] Last Gasp is an automatic notification by the AMF meter indicating an interruption of electrical service at the meter. Power Up is an automatic notification by the AMF meter indicating the restoration of electrical service at the meter.

Prepared by or under the supervision of: Philip J. Walnock and Wanda Reder

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Division 3-17

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

How does RIE plan to leverage the proposed customer outage alerts system to reduce the need for customers to call in? How will RIE leverage PPL experience to have an improved experience over PPL?

Response:

PPL Electric Utilities Corporation's ("PPL Electric") implementation of Last Gasp meter alert functionality in Pennsylvania has reduced the need for customers to report an outage. Prior to the advanced metering infrastructure ("AMI") deployment, PPL Electric primarily relied on customers to contact the utility to report an outage. Last Gasp meter alerts have enabled PPL Electric to respond to and restore outages without receiving a call from a customer. From August 2019 through July 2020, PPL Electric was able to restore approximately 19% of outages without a customer reporting an outage from the use of Last Gasp meter alerts. Two years later, beginning in August 2020 through July 2022, the number of customers being restored without reporting an outage increased to approximately 25% on average.

The implementation of Last Gasp meter alerts in Pennsylvania will serve as the foundation for Rhode Island Energy. The system technical plan and business process designs used in Pennsylvania will be leveraged for the Rhode Island Energy implementation. Once fully implemented, Rhode Island Energy sees the use of Last Gasp and Power Up functionality as an opportunity to improve and enhance customer experience.

Prepared by or under the supervision of: Philip J. Walnock

Division 3-18

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

How does RIE currently populate its system outage maps showing locational data, number of customers without power, and estimated restoration time? How will this change with AMF implementation?

https://outagemap.rienergy.com/

Response:

RIE currently populates the system outage map with data from the Outage Management System which is the source system for outage related data. This will not change with AMF implementation.

Prepared by or under the supervision of: Philip J. Walnock

Division 3-19

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

The Company indicates that AMF provides near real time monitoring of customer's electric usage data in 15-minute increments. What is "near real-time" in terms of actual time. In the case of an outage at a customer premise, what is the time frame that RIE would actually receive notification of the outage relative to the time of the "Last Gasp" function of the AMF meter? Will "Last Gasp" functionality be integrated and operational at the time each meter is set and how is this aligned with OMS development?

Response:

The advanced metering functionality ("AMF") meters are planned to send back 15-minute interval usage data over the RF mesh communication network to back-office systems, with a planned 30-45 minute delay in data availability for a customer to view via the customer portal.

The planned Rhode Island Energy radio frequency ("RF") communications network is an enhancement over the current Pennsylvania RF communication network, including both Wi-Sun functionalities as well as a targeted 3 hop-count specification. PPL Electric Utilities Corporation ("PPL Electric") in Pennsylvania does not have a specific metric that tracks the actual last gasp trigger time one-way from the AMF meter back to PPL Electric. PPL Electric does track the roundtrip time performance from the head-end system to/from the meter and back to the head-end system. From the most recent sample set of approximately 3000 end points, the average duration was 8.19 seconds, with the fastest being 2 seconds and the longest being 97 seconds. Additionally, feedback from the PPL Electric dispatch group is that after the 35 second recloser trigger delay in the AMF meter, the notification feels almost instantaneous, with the majority within one minute of total time to seeing a trip on the systems (including AMF meter recloser delay time).

The AMF and OMS technical implementation schedules are aligned with last gasp power up capabilities being available upon planned completion for the first meter deployment sector, and moving forward.

Division 3-20

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

How is RIE proposing to track, measure and validate the forecasted benefits for Faster Restoration Time?

Response:

Restoration time is measured by CAIDI. CAIDI will continue to be measured; however, it will not be impacted by faster notification from advanced metering functionality ("AMF") Last Gasp because the CAIDI clock starts when the outage is initiated in the Outage Management System ("OMS"). Rhode Island Energy will have the ability to generate a dataset to track the variance between the timestamp of the "Last Gasp" outage notification and the timestamp for the first customer-initiated notification for the outage in OMS, using the same approach that PPL Electric Utilities Corporation has used to determine the 22-minute outage notification benefit. The difference in outage notification time can be tracked and compared to the assumptions that were used in the AMF benefit-cost analysis.

Prepared by or under the supervision of: Wanda Reder

Division 3-21

Questions regarding RIE's response to DIV 1-17; 22-minute outage notification time difference.

Request:

Has PPL identified and/or quantified "Last Gasp" benefits in other jurisdictions in its AMF Business Case? If so, explain the methodologies utilized and how the jurisdiction has validated the benefits after AMF was deployed. Provide a reference to corresponding regulatory filings or other supporting documentation.

Response:

Please see the table below for references to PPL regulatory filings in Pennsylvania and Kentucky.

State	Organization	URL	Last Gasp Reference
KY	Kentucky Utilities Company	https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp%40lge-ku.com/11252020084757/10-KU_Testimony_1of4%28Thompson_Blake_Bellar_Sinclair_Wolfe_Saunders%29.pdf	Page 203, Pages 311-314
KY	Louisville Gas & Electric Company	https://psc.ky.gov/pscecf/2020-00350/rick.lovekamp%40lge-ku.com/11252020085918/10-LGE_Testimony_1of4%28Thompson_Blake_Bellar_Sinclair_Wolfe_Saunders%29.pdf	Page 203, Pages 311-314
PA	PPL Electric Utilities Company	https://www.puc.pa.gov/pcdocs/1296056.pdf	Document Pages 83-85; SMP Pages 51-53

In Pennsylvania, outage management benefits associated with the introduction of Last Gasp and restoration messages are outlined but not quantified. PPL Electric Utilities Corporation plans to reflect operational savings related to Last Gasp in future base distribution rate cases.

In Kentucky, outage management benefits are both discussed and quantified. Last Gasp benefits for the Electric Distribution Operations group are included in an overall outage management benefit that was calculated based on improved efficiencies leading to a reduction in overtime. As Last Gasp meter alert functionality has not been fully implemented in Kentucky, there is no validation of the benefits yet.

Division 3-22

Questions on Bonenberger Testimony

Request:

[Bonenberger testimony] Please provide copies of any reports that RIE used to assess the availability of land for additional DER development.

Response:

Rhode Island Energy did not assess availability of land for additional distributed energy resources ("DER") development. However, there are reports available that provide insight into solar citing opportunities within the state of Rhode Island, two of which are highlighted in this response.

The Solar Citing Opportunities Report prepared for the Rhode Island Office of Energy Resources in August 2020 states, "Synapse's granular bottom-up geospatial analysis of Rhode Island's solar potential demonstrates that the state is host to between 3.4 and 7.3 GW of solar technical potential, with commercial and industrial developed and undeveloped parcels representing the largest category—up to 4.6 GW. Parking lots represent the second-largest category, though the state has seen only very limited parking lot solar installations (e.g., fewer than ten) to date. Within the residential category, single family rooftops have a higher economic potential than multifamily rooftops, with a potential up to 220 MW, concentrated in the eastern portion of the state."

The same report by Synapse, "finds that the state has ample room on built environments to expand its solar-energy generation. Already-developed sites across the state can host between 3,390 megawatts and 7,340 megawatts of renewable power, or about 13-30 times the amount currently installed in the state. This translates into 5,560 gigawatt-hours to 12,600 gigawatt-hours of potential electricity production. Rhode Island's annual wholesale electric load is 7,826 gigawatt-hours of electricity." The report concludes that Rhode Island can produce a greater amount of electricity than it consumes by installing solar arrays on more roofs, landfills, brownfields, gravel pits, and parking lots. Additionally, "open space advocates say the analysis, Solar Siting Opportunities for Rhode Island, proves that woodlands, meadows, and farmland don't need to be cleared and covered to meet state renewable-energy objectives. As such, the 83-

page report excludes farmland, residential open spaces, and state and municipal land from Rhode Island's inventory of solar potential."[1]

An additional report prepared by Rhode Island Office of Energy Resources (OER) and The Brattle Group in December 2020, "The Road to 100% Renewable Electricity by 2030 in Rhode Island," contains a key insight that "Rhode Island's goal of 100% renewable electricity by 2030 is achievable. Renewable resources are available within Rhode Island and in surrounding areas to support this goal."

A copy of the Solar Siting Opportunities for Rhode Island report is provided as Attachment DIV 3-22-1.

A copy of The Road to 100 Percent Renewable Electricity report is provided as Attachment DIV 3-22-2.

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[1] New Report Finds Rhode Island has Plenty of Room to Expand Solar Responsibly - ecoRI News

Solar Siting Opportunities for Rhode Island

An analysis of potentials and costs of rooftop, landfill, gravel pit, brownfield, commercial and industrial ground-mounted and carport solar

Prepared for Rhode Island Office of Energy Resources

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CONTENTS

EXECUTIVE SUMMARY

As of Spring 2020, over 250 megawatts (MW) of solar have been interconnected with Rhode Island's distribution system. In an effort to assist with planning future solar photovoltaic (PV) development within the context of other land-use interests such as conservation, agriculture, and housing development, the Rhode Island Office of Energy Resources (OER) contracted Synapse Energy Economics to develop an estimate of the likely solar potential available within a number of solar siting categories. We conducted this statewide study using a granular bottom-up approach, primarily through the use of geospatial data and geographic information system (GIS) software. We used data obtained from the Rhode Island Geographic Information System (RIGIS) clearinghouse, National Grid, RI Commerce Corporation, local solar developers, RI Housing, University of Rhode Island, RI Department of Environmental Management (DEM), United States Geological Survey (USGS), National Renewable Energy Laboratory (NREL), United States Environmental Protection Agency (US EPA), and parcel and zoning data from nearly all cities and towns in the state.[1]

Methodology and data sources

Synapse examined and quantified solar potential for the following six siting categories:

- Rooftop solar (including rooftops of residential single family, residential multifamily, commercial, industrial, municipal, and other building types)
- Ground-mounted solar in the following four categories: (1) Landfills, (2) gravel pits, (3) brownfields, and (4) commercial and industrial developed and undeveloped lots
- Parking lot / carport solar

These categories were identified by OER as types of locations that could aid in policymakers' decisions for balancing future solar PV development with other land use interests such as conservation, farming/agriculture and housing development.

All data and analysis in this study was carefully assembled with stakeholder engagement, including town planning agencies, state agencies, National Grid, solar developers, University of Rhode Island, and members of the public. This stakeholder engagement was done through a kickoff presentation and Q&A session with stakeholders, an interim project update document circulated to stakeholders, a survey sent to solar developers, and telephone outreach to town planners, solar developers, and state agencies. Wherever possible, we spoke with a variety of stakeholders in order to provide a broad set of views on

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[1] Note that data on existing solar installed in Block Island Power Company and Pascoag Utility District service territories were not used in this analysis.

specific assumptions such as incremental solar costs for specific categories, typical project setbacks, topology requirements, and other topics.

We used geospatial analysis to examine the following types of potentials for each category of solar:

- **Total Potential,** an estimate of the solar potential for the entire area under consideration, with no exceptions.
- **Technical Potential,** an estimate of the potential excluding areas not suitable for solar development. Figure 1 and Figure 2 highlight some challenges facing rooftop solar and certain ground-mounted solar installations. These challenges may reduce technical potential, relative to total potential.

For residential rooftop solar, we also analyzed:

- **Economic Potential,** an estimate of the solar potential that is likely to be installed, given the current cost of the technology, the current financial incentives available, and the household economics specific to a municipality.

In addition, for each category of solar, we compiled estimates of these MW potentials translated into gigawatt-hour (GWh) generation potential, solar costs (based on costs available as of late 2019 / early 2020), avoided greenhouse gas emissions, and possible impacts on distribution system hosting capacity.

Figure 1. Siting challenges that may reduce technical potential for rooftop solar

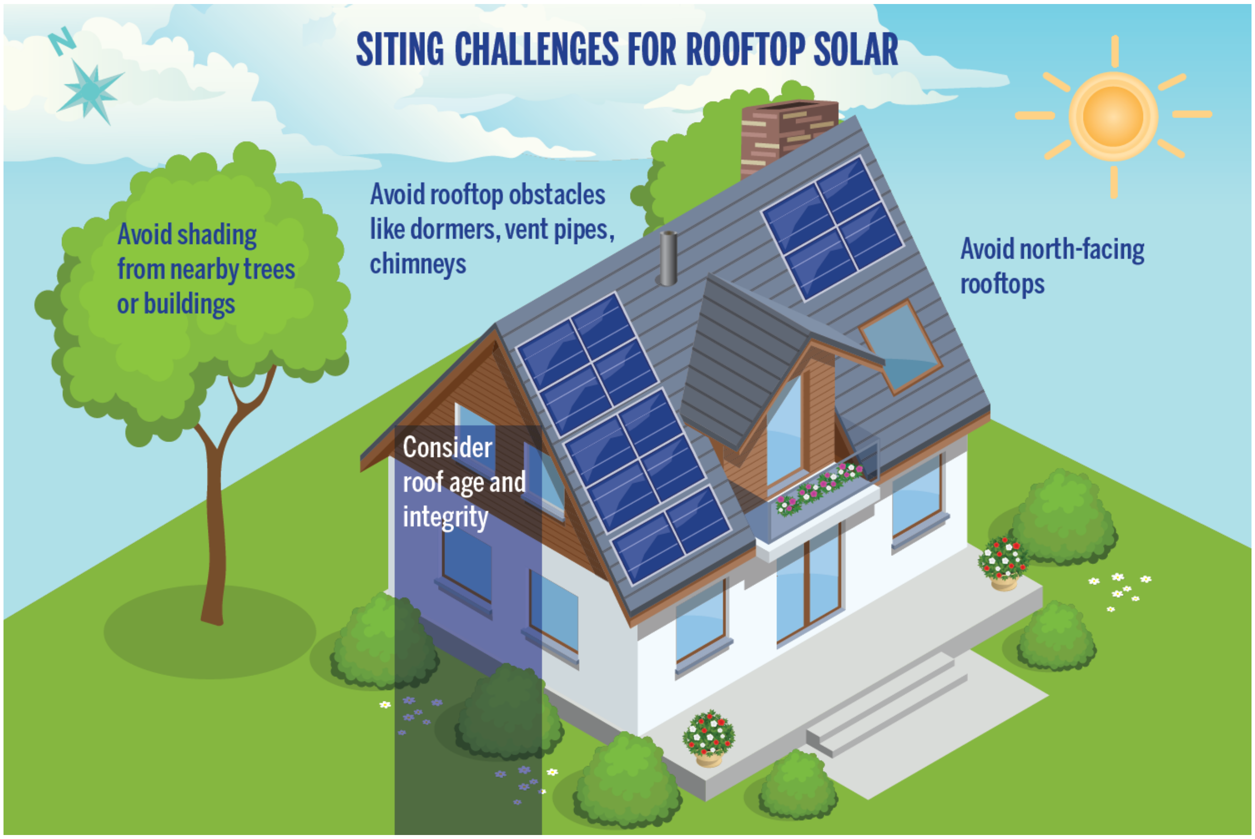
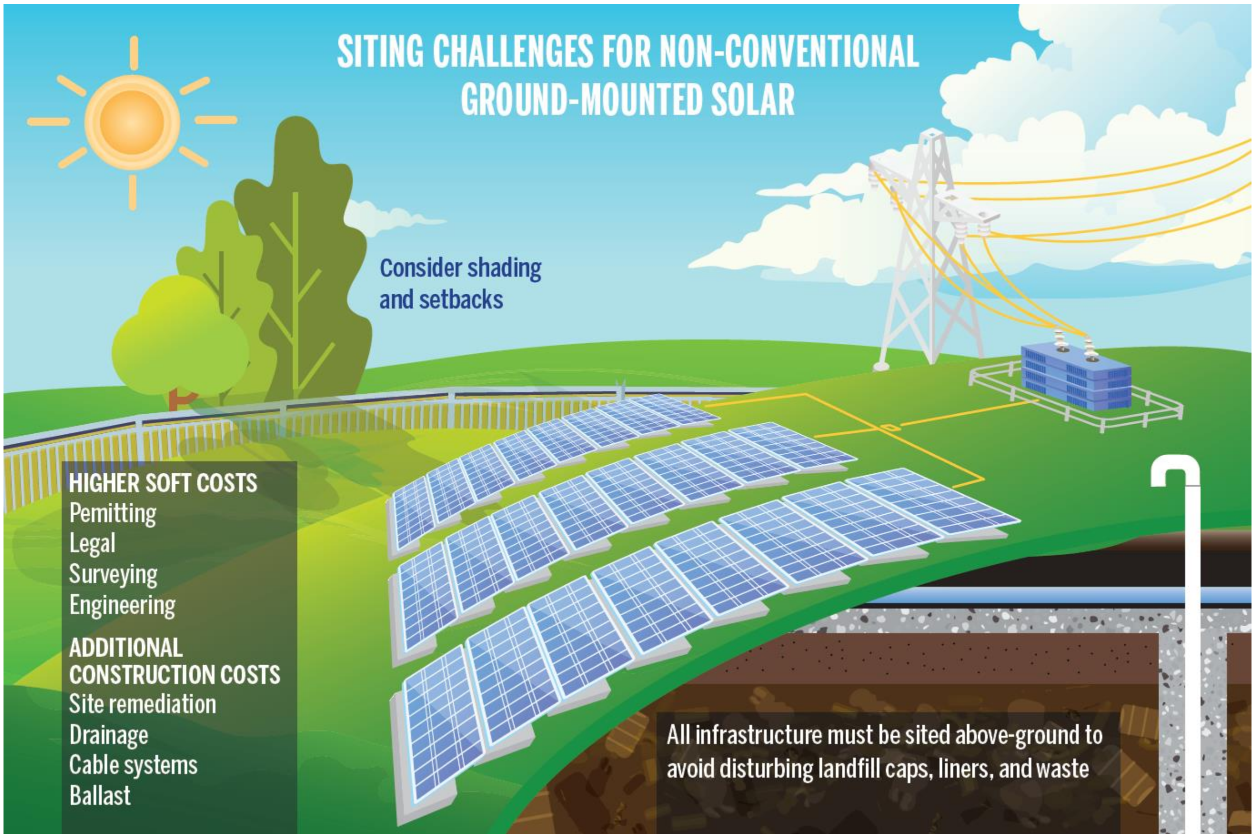


Figure 2. Siting challenges that may reduce technical potential for non-conventional ground-mounted solar (e.g., on landfills, gravel pits, or brownfields)



Findings

Table 1 displays a high-level summary of the results of our analysis for all types of solar, while Table 2 displays the summary of solar potentials (including economic potential) for residential rooftop solar. Ranges under technical potential illustrate the range of possible potential assuming different input parameters; ranges for rooftop solar costs illustrate the median costs for non-residential (low number) and residential systems (high number). Wherever possible, we have assembled cost data specific to each category; for ground-mounted solar categories, detailed, comprehensive cost data for each category were not available, and a typical cost for ground-mounted solar is shown instead.

We find that in aggregate across all six categories analyzed, technical potential for solar is between 3,390 megawatts (MW) and 7,340 MW, or 13 to 30 times the amount of solar that is currently installed in Rhode Island. This translates into 5,560 gigawatt-hours (GWh) to 12,600 GWh of electricity able to be produced. Median estimated upfront prices for these categories range from about $3 to $5 per watt. If this entire technical potential were installed, we estimate that up to 7.65 million metric tons of carbon dioxide (MMTCO$_2$) could be displaced, equal to about 70 percent of Rhode Island's total, current greenhouse gas emissions.

Table 1. Summary of potentials and costs

Category	Technical potential (MW)	Technical potential (GWh)	Estimated cost ($/Watt-DC)	Estimated cost ($/MWh-AC)	Potential avoided GHG emissions (MMTCO2)
Rooftop	850	1,130	\$3.07 – \$4.15	\$153 – \$208	0.74
Landfills	70 – 260	120 – 450	\$3.21	\$122	0.07 – 0.27
Brownfields	260 – 650	450 – 1,120	\$3.21	\$122	0.27 – 0.69
Gravel pits	30 – 90	50 – 160	\$3.21	\$122	0.03 – 0.10
Commercial and industrial parcels	1,160 – 4,600	1,990 – 7,920	\$3.21	\$122	1.21 – 4.83
Parking lots	1,060	1,820	\$5.09	\$188	1.19
Total	**3,390 – 7,340**	**5,560 – 12,600**	**-**	**-**	**3.47 – 7.65**

Table 2. Summary of total, technical, and economic potentials for residential rooftop solar

Subcategory	Total potential (MW)	Technical potential (MW)	High Economic Potential (MW)	Low Economic Potential (MW)
Residential Single Family	2,100	440	220	90
Residential Multifamily	480	100	40	20
Total	**2,580**	**540**	**260**	**110**

Finally, we compared the hosting capacity of 3-phase distribution lines in Rhode Island to the technical potential of solar in each town. We find that about 85 percent of towns in the state have an average hosting capacity that is less than its average technical solar potential. This exercise may be useful in determining where distribution system upgrades should be prioritized.

Caveats and limitations

All numbers provided in this report are intended to be high-level, first-pass estimates. In many solar categories, the accuracy of our estimates is limited by the data available. For example, we reached out to all 39 towns and cities and received zoning and parcel data from 35 municipalities. For municipalities that provided data, we contended with data in different formats, of different zoning vintages, and of various levels completeness. For the municipalities for which we did not receive zoning and parcel data, we used U.S. Census data (including housing density, median income, and population) to identify similar municipalities to apply known zoning category breakdowns. This implies that the actual rooftop and commercial and industrial-sited solar potentials may be higher or lower than estimated in this report, depending on the actual zoning in place in each municipality. Other datasets used in our GIS analysis, including data describing landfills, brownfields, gravel pits, and parking lots may be incomplete or partially out-of-date, creating uncertainty in the solar potentials estimated here. Some information—such as the historical data used to inform dollar-per-watt costs—may be based on a limited number of data points. For carports in particular, our cost estimates were based on two installations that existed in Rhode Island as of Fall 2019. Costs may change as more projects are built and the market matures.

In addition, in order to simplify the study, we applied several general assumptions on solar siting. These include the quantity of solar that can be built on a single rooftop or parcel (measured in kilowatts per square meter), the effective electrical output of a solar facility (measured in megawatt-hours), the slope of land that is practical for solar construction, and the setbacks required on each parcel (required by zoning or shading from adjacent buildings and trees).

Importantly, solar potentials at individual locations should be calculated based on any additional site-specific information available. Further caveats and limitations are detailed in the report.

Conclusions

Though Rhode Island is host up to 4,680 MW of solar potential on rooftops, brownfields, landfills, gravel pits, and parking lots, the cost of developing these sites may be higher than equivalent installations on conventional ground-mounted sites due to additional permitting, construction, and site remediation costs. These incremental costs are likely to be site-specific and vary across sites with different characteristics. Though siting solar on these types of sites may address siting or environmental concerns, there are potential tradeoffs given potentials for additional costs and lower-than-average annual generation. Furthermore, hosting capacity limitations may also pose a tradeoff when deciding where to site solar projects. Our analysis indicates there are many towns across the state where distribution hosting capacity upgrades may be advantageous for interconnecting the state's future solar potential.

This study was commissioned by the Rhode Island Office of Energy Resources. Please contact Chris Kearns at christopher.kearns@energy.ri.gov with any questions.

1. INTRODUCTION TO SOLAR POTENTIALS AND COSTS

In this analysis, we evaluated the potential of solar photovoltaic (PV) in Rhode Island in the following six siting categories:

- Rooftop solar (including rooftops of residential single family, residential multifamily, commercial, industrial, municipal, and other building types)
- Ground-mounted solar in the following four categories:
    - Landfills
    - Gravel pits
    - Brownfields
    - Commercial and industrial (C&I) developed and undeveloped lots
- Parking lot / carport solar

These categories were identified by Rhode Island's Office of Energy Resources (OER) as types of locations that could aid in policymakers' decisions for balancing future solar PV development with other land use interests such as conservation, farming/agriculture and housing development. For all ground-mounted categories, we analyzed parcels that are both completely undeveloped (e.g., devoid of any existing buildings), as well as parcels that currently have existing buildings in place. For this latter type of parcel, we examined the available area after removing any area associated with building footprints or existing solar installations. Note that we did not analyze any parcels that were zoned for residential use.

For these six siting categories, we assess three different types of solar potentials: total, technical, and economic. For the purpose of this analysis, these terms are defined as follows:

- **Total potential** refers to the entire area under consideration, with no exceptions (i.e., what if a parcel were completely covered in solar panels, irrespective of topography, setbacks, or other site restrictions?), less solar capacity currently installed through Fall 2019. As a result, this category is likely to be an overestimate of all solar that could be built in any one parcel. We do not remove any "in progress" solar capacity—this means we are ignoring projects that are awaiting activation or are under construction, as well as projects that are merely proposed. We evaluate total potential for every solar category.
- **Technical potential** is a subset of total potential that includes only geographic areas that are suitable for solar development. Unsuitable areas might include areas that are too close to adjacent parcels (and thus impacted by shading or setback requirements), roof areas that are primarily shaded or occupied by poor rooftop geometry, areas with very steep slopes, areas currently occupied by wetlands or other non-compatible land uses (such as rivers, ponds, and rock outcroppings), or available hosting capacity on the distribution system. We evaluate technical potential for every solar category.

- **Economic potential** is a subset of technical potential that evaluates the amount of solar that is likely to be installed given the current cost of the technology, available financial incentives, and municipal household economics.[2] Economic potential was only calculated for residential buildings (both single family and multifamily).

For each potential category above, we report both capacity and energy generation results. Capacity values throughout the report are described in terms of megawatts alternating current (MW_{AC}), unless otherwise specified. Table 3 displays the known quantity of solar installed in Rhode Island through Fall 2019.[3] As described above, this solar was removed from all estimates of potential. We did not remove any solar capacity that is "in progress" (i.e., projects that are awaiting activation or are under construction). For a full list of existing solar installations in Rhode Island by municipality, see Appendix A.

Capacity and generation

Throughout this report, we report results for both capacity and energy generation results. **Capacity**, measured in megawatts (MW), describes the maximum electric output a generator can produce at one point in time. Meanwhile, **generation**, measured in megawatt-hours (MWh) or gigawatt-hours (GWh)—equal to one thousand MWh—is the estimated electricity that can be produced over a period of time. For example, if a solar facility with a capacity of 1 MW can generate electricity at its maximum value over 1 hour, it will produce 1 MWh of electricity. In practice, the output from solar facilities varies over the course of the day, with peak capacity being reached mid-day.

Capacity and generation values in this report are described in terms of alternating current (MW_{AC} and GWh_{AC}), the type of electricity used by the grid, rather than direct current (DC), which is the type of electricity produced by solar facilities. Most solar facilities convert DC electricity into AC electricity through the use of an inverter, although some output is often lost during this conversion.

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[2] This category does not consider non-economic drivers such as a customer's desire for lower emissions or aesthetics.

[3] Throughout this report, we refer to existing quantities as of solar that were installed as of Fall 2019. Data provided by National Grid indicates that as of March 31, 2020, an additional 53 MW of solar was also installed. However, detailed data on the program categories or locations of these facilities has not been provided. Note that data on existing solar installed in Block Island Power Company and Pascoag Utility District service territories were not used in this analysis.

Table 3. Rhode Island solar installations and capacity by type, as of Fall 2019[4]

Type	Subtype	Total Installations	Total MW-AC
Rooftop	Residential	7,341	44
Rooftop	Commercial	208	21
Ground-mounted	All	164	121
Other (carports, brownfields)	All	10	12
Total		**7,723**	**198**

Note: The data above comes from the following programs: Renewable Energy Fund, Renewable Energy Growth (Small), Renewable Energy Growth (Medium, Large, and Commercial), Virtual Net Metering Program, Distributed Generation Standard Contracts Program, the 30 MW Community Solar Virtual Net Metering Pilot Program, and earlier non-programmatic net-metering. This does not include solar installed between Fall 2019 and March 2020, which is estimated to total around 53 MW. Source: RI Commerce Corporation and National Grid.

All data and analysis in this study was carefully assembled with stakeholder engagement, including town planning agencies, state agencies, National Grid, solar developers, University of Rhode Island, and members of the public This stakeholder engagement was done through a kickoff presentation and Q&A session with stakeholders, an interim project update document circulated to stakeholders, a survey sent to solar developers, and telephone outreach to town planners, solar developers, and state agencies. Wherever possible, we spoke with a variety of stakeholders in order to provide a broad set of views on specific assumptions such as incremental solar costs for specific categories, typical project setbacks, topology requirements, and other topics.

In the following sections we describe how we calculated the total, technical, and economic potentials for each of the six siting categories of solar (rooftops, brownfields, landfills, gravel pits, developed and undeveloped

Key sources

This analysis relies on data and methodologies from several other recent solar analyses. Several of the most relevant studies include:

- Boving, T., P. Cady, D. Musher, T. Davis, and C. Damon. 2011. “Rhode Island Renewable Energy Siting Partnership Final Report, Volume 2 Technical Reports, RESP Technical Report #8.” University of Rhode Island. Available at https://www.crc.uri.edu/download/resp_volume_2_final.pdf.
- Brown, A., P. Beiter, D. Heimiler, C. Davidson, P. Denholm, J. Melius, A. Lopez, D. Hettinger, D. Mulcahy, and G. Porro. 2016. “Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results.” National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy15osti/64503.pdf.
- Gagnon, P., R. Margolis, J. Melius, C. Philips, and R. Elmore. 2016. “Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment.” National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy16osti/65298.pdf.

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[4] Data was obtained at different points in the study process. For example, data on the REF program is up-to-date through August 31, 2019. Meanwhile, data on the REG program is up-to-date through November 1, 2019. Data on all other project categories are up-to-date through November 30, 2019.

commercial and industrial parcels, and parking lots). Note that this includes analysis of sites (such as defunct landfills and brownfields) that may appear very green though years of natural regrowth and mask what the underlying land actually is. Wherever possible, we strived to present potentials for all categories on an apples-to-apples basis, so that each type of potential is comparable across the types of solar. For most categories, we present ranges of results. The purpose of these ranges is to reflect the uncertainty in some of the key drivers of our potential calculations.

Note that all numbers provided in this report are intended to be high-level, first-pass estimates. Solar potentials at individual locations should be calculated based on any additional site-specific information available.

2. ROOFTOPS

The first category analyzed is rooftop solar. For the purposes of this analysis "rooftop solar" refers to any solar facility constructed on the roof of a building. In this analysis, we subcategorize buildings as residential single family, residential multifamily, commercial, industrial, municipal, mixed use, and other.[5]

Table 4. Summary of potentials and costs, rooftops

Subcategory	Total potential (MW)	Technical potential (MW)	Technical potential (GWh)	Technical potential avoided GHG emissions (MT CO2)
Residential Single Family	2,100	440	580	377,600
Residential Multifamily	480	100	140	89,900
Commercial	360	13	170	110,200
Industrial	230	110	150	96,600
Municipal	50	20	20	15,400
Mixed Use	50	10	20	9,700
Other	140	40	60	38,500
Total	**3,400**	**850**	**1,130**	**737,800**

Note: In this table, and throughout the report, all values have been rounded to the nearest 10.

2.1. Rooftop solar potential

For the calculation of total, technical, and economic rooftop solar PV potentials in this study, we primarily relied on three data sources: a polygon shapefile of building footprint areas obtained from the RI GIS[6], polygon shapefiles of parcels and zoning designations provided by towns and cities throughout Rhode Island,[7] and a 2016 study on rooftop solar by National Renewable Energy Laboratory (NREL).[8] The following sections describe the methodology used to estimate total, technical, and economic potential for each of the rooftop subcategories considered.

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[5] "Other" may include buildings owned by the state, federal government, or an unknown entity.

[6] Rhode Island Geographic Information System. 2018. Building Footprints. Available at: http://www.rigis.org/datasets/building-footprints.

[7] See Appendix B for detail on GIS data provided by municipalities.

[8] Gagnon, P., R. Margolis, J. Melius, C. Philips, and R. Elmore. 2016. "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment." National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy16osti/65298.pdf.

Total potential

Total potential refers to the entire quantity of rooftop solar possible, less the solar capacity currently installed through Fall 2019.

Data and methods

First, we used a GIS shapefile from RI GIS containing polygons of building footprints across the state.[9] This dataset, which encompassed buildings in every city and town in Rhode Island, was used as a proxy for rooftop area. We then combined this polygon shapefile of building footprints with the shapefiles of parcel and zoning data, provided by towns and cities in Rhode Island, to code each building footprint to a particular zoning type.[10] Each zoning type was then coded to one of the seven types of building categories. Building size (small, medium, large) was assigned for each building using a GIS function that calculates the area of each polygon. In total, we analyzed approximately 367,000 rooftops statewide.

What is a shapefile?

The solar siting analysis performed in this report relies on data readable in geographic information systems (GIS) software. This software is commonly used by town planners and other analysts to examine the relationships between data commonly used to create geographical maps. This data is often organized into “shapefiles” which can attach spreadsheet-based data (e.g., addresses, population, zoning designations, building age) to the data of geographic attributes. In this analysis, we typically use two types of shapefiles:

- **Polygon shapefiles**, which contain an aggregation of aggregate many different individual shapes or areas. Example shapefiles include building footprints and municipality parcels.
- **Point shapefiles**, which contain an aggregation of sites represented by single points (often the geographic center of a site). Example shapefiles include gravel pit center points.

Next, we relied on several rooftop-related parameters calculated by NREL to convert building footprint area into MW. In 2016, NREL published a comprehensive assessment of rooftop solar technical potential for the United States in different U.S. metro areas (including Providence and other metro areas in southern New England). Within this study, the authors developed a methodology to assess rooftop characteristics based on building type (i.e., small, medium, large) and municipality type (e.g., midsize city, large suburb) for nationwide building data. NREL categorized each building by total square footage: small (less than 5,000 square feet), medium (greater than 5,000 but less than 25,000 square feet), and large (25,000 square feet or greater).

We calculated total capacity potential (in MW) for rooftops by multiplying the total rooftop area of each building size category in each municipality by the capacity values (kW/m^2) from the NREL study specific to each combination of building size and municipality type. Finally, we subtracted the MW quantity of

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[9] Rhode Island Geographic Information System. 2018. Building Footprints. Available at: http://www.rigis.org/datasets/building-footprints.

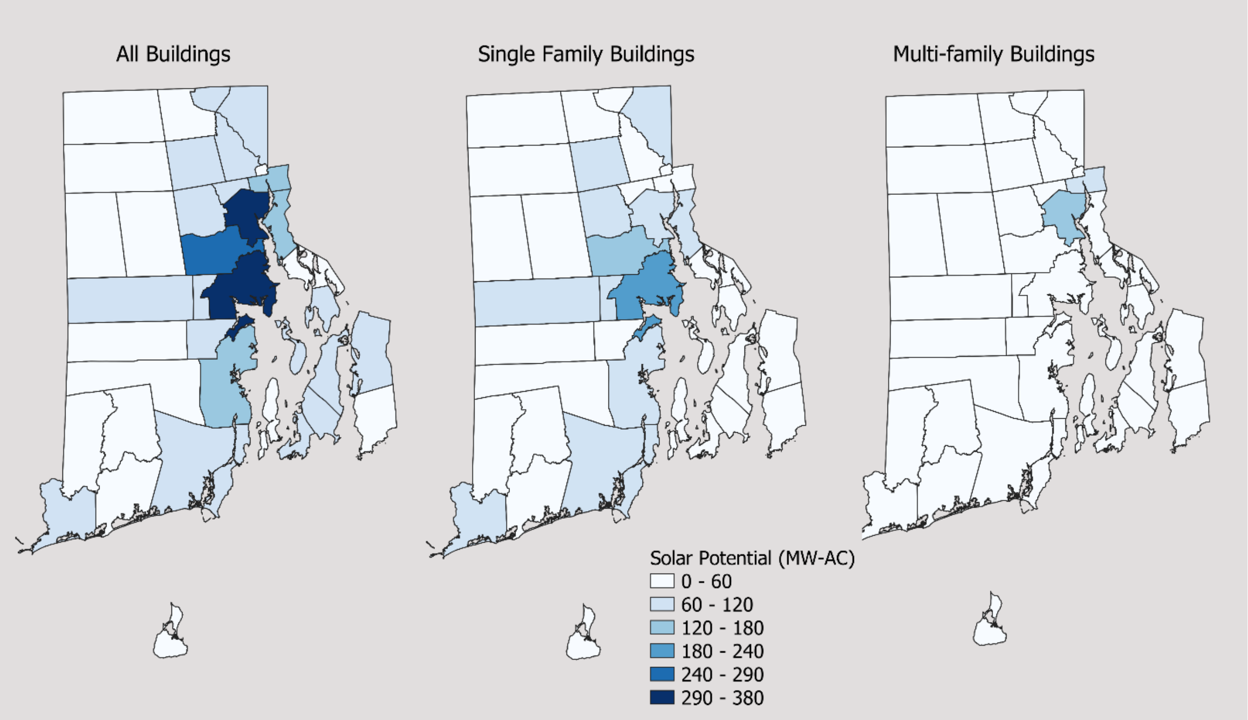
[10] Parcel and zoning shapefiles were provided to us by individual city and town governments.

rooftop solar that was installed in Rhode Island as of Fall 2019, according to data provided by National Grid and the RI Commerce Commission.[11]

Findings

Using this approach, we find that all municipalities have at least 13 MW of total rooftop solar potential (see Figure 3). The average municipality has about 90 MW of rooftop solar potential. Statewide, there is a total potential of about 3,400 MW with nearly half of that in the residential single-family category (see Figure 4 and Figure 5). This total potential value is in line with an estimate for Rhode Island derived in NREL's 2016 analysis of 3,800 MW.[12]

Figure 3. Map of rooftop solar total potential by municipality and building type (MW)



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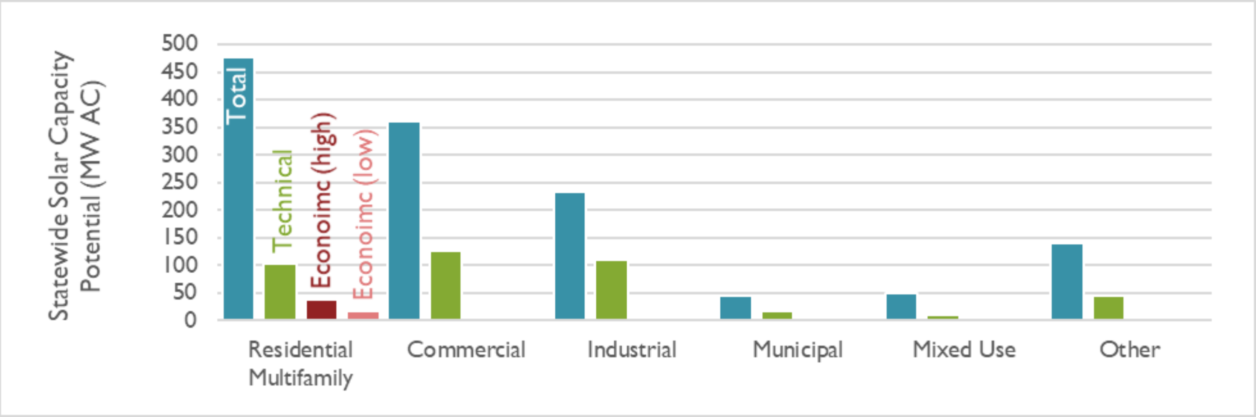
[11] This includes rooftop solar installed under the Renewable Energy Fund (REF) with net metering program, the Renewable Energy Growth (REG) program, and other installations not affiliated with either program.

[12] This difference (3,800 MW versus 3,400 MW) is within the range of expected difference between two studies with fundamentally different approaches to estimating rooftop solar potential. Possible causes of the difference include using different datasets for building footprints, and the fact that NREL's estimate is calculated only for the Providence metro area then extrapolated to the rest of the state, whereas this analysis has been performed using municipality-specific data for all 39 municipalities.

Figure 4. Rooftop solar capacity potential results (residential single family only)

Note: ***Total potential*** *refers to the entire area under consideration, less the solar capacity currently installed through Fall 2019.* ***Technical potential*** *is a subset of total potential that includes only areas that are suitable for solar development.* ***Economic potential*** *is a subset of technical potential that evaluates the amount of solar that is likely to be installed given the current cost of the technology, available financial incentives, and municipal household economics.*

Figure 5. Rooftop solar capacity potential results, by building category (all other rooftop categories)



Note: "Other" contains federal, state, and other miscellaneous or unknown building types.

Technical potential

Technical potential is a subset of total potential that includes only areas that are suitable for solar development.

Data and methods

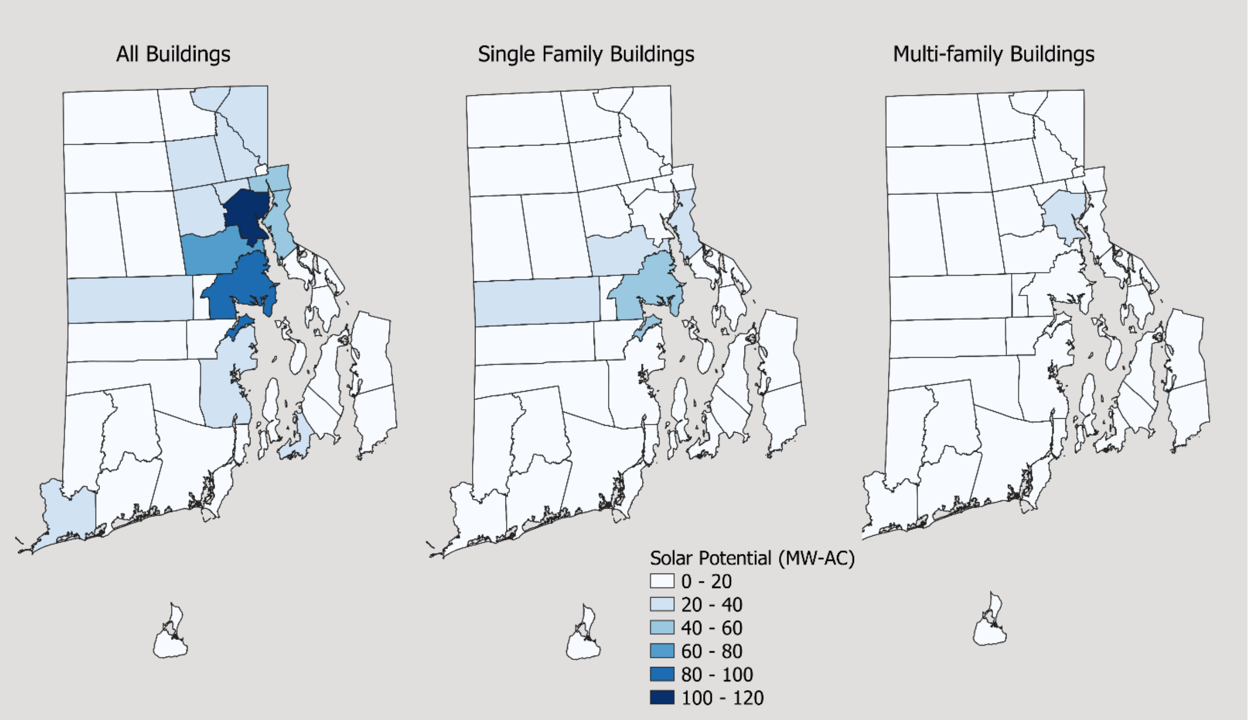
To calculate the technical solar PV potential, we used the same methodology described above for total potential, but also incorporated a factor to account for the subset of rooftop areas that are suitable for solar. For each combination of building and municipality type (e.g., small buildings in a midsize city), NREL calculated the fraction of rooftop space that is likely to be suitable for solar PV (based on building shading, tilt, azimuth, and the solar PV capacity (reported in kW_{AC}) per square meter of rooftop space using LIDAR data in NREL study obtained from the U.S. Department of Homeland Security (DHS)

Homeland Security Infrastructure Program for 2006–2014.[13] The resulting fractions of building area determined to be suitable varies depending on the municipality in which the building is located and the size of the building (small, medium, large). The fractions range from 17 percent to 79 percent, with smaller buildings tending to have a smaller share of rooftop area suitable for solar, and larger buildings tending to have a larger share of rooftop area suitable for solar.

Findings

The technical screening reduces the total rooftop solar potential to about 25 percent of the original estimate—about 850 MW (Figure 4). All municipalities have at least 3 MW of technical rooftop solar potential. The average municipality has about 22 MW of rooftop solar technical potential (Figure 6). According to the dataset used, about 3 to 5 percent of residences are not suitable for any solar (about 12,000 households). These are buildings with have effectively no roof planes suitable for installing even a small amount of solar. The technical screening reduces residential (single and multifamily) rooftop solar potential from a total potential of 2,580 MW to a technical potential of 550 MW.

Figure 6. Map of rooftop solar technical potential by municipality and building type (MW)



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[13] Additional detail on this DHS study can be found in section 3.1 of the 2016 NREL Report "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessments." LIDAR is a method for measuring distances with laser lights, and is commonly used to develop GIS shapefiles that articulate the change in elevation of a particular area.

Economic potential

Economic potential is a subset of technical potential that evaluates the amount of solar that is likely to be installed given the current cost of the technology, available financial incentives, and municipal household economics.

Data and methods

We relied on three parameters to provide a range of how much of the technical potential might be economic : (1) range of solar costs, (2) range of incentives Renewable Energy Fund (REF) with net metering or Renewable Energy Growth (REG) incentives, and (3) range of median household income according to U.S. Census data.[14, 15, 16] Given the large variation in these parameters, we calculate two economic potential values—a low and a high—representing a range of possible economic solar potential for each city or town.

First, we estimated total project to determine the simple payback period of an average-sized solar PV system, under (a) the REF program with net metering and (b) the REG program, as they existed in early 2020 (see Appendix C for more information on the REG and REF programs). A "payback period" refers to the length of time it will take for an investor to recover their initial investment cost. The payback period used in this analysis is a simple payback period and does not include any discounting. We examined the estimated payback for both the REF program with net meter and the REG program, each under two different assumed upfront solar costs: a low cost equal to the 20th percentile cost of small-scale rooftop installed in the REF and REG programs since 2018, and a high cost equal to the 80th percentile cost of cost of small-scale rooftop installed in the REF and REG programs since 2018. This payback analysis yielded four different estimated payback periods.

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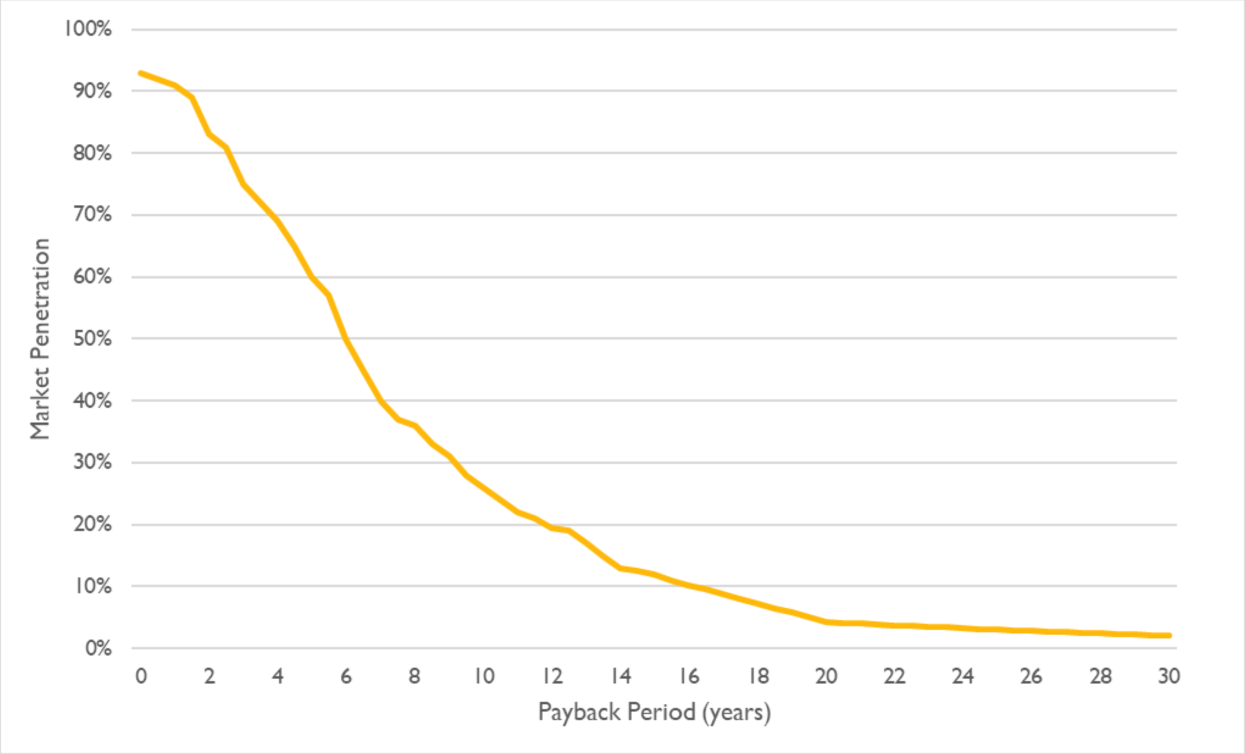
[14] Additional information on the REF net metering program: Rhode Island law requires National Grid to offer a net metering tariff for customers with distributed generation. Net metering can be paired with grants from the Renewable Energy Fund, but not with the Renewable Energy Growth program. The current implementing law was passed in 2011, and as of 2014 there was no cap on the total amount of renewable capacity that can participate. When a customer enrolls in net metering, any generation they export to the grid offsets an equivalent amount of electricity consumed from the grid and reduces the customer's electric bill. Customers are credited at a value equal to the sum of the current supply and delivery costs, except for the energy efficiency and renewable energy charges. Excess generation beyond a customer's total consumption is compensated at the utility's avoided cost rate up to an additional 25 percent of a customer's consumption. Distributed generation must be connected to the grid at the same place as the customer's load to be eligible for net metering, though there are exceptions through virtual net metering and the community solar pilot.

[15] REF incentive assumptions are based on a Request for Projects dated December 30, 2019 (See https://commerceri.com/wp-content/uploads/2019/05/Small-Scale-Solar-Requests-for-Projects-12.30.19.pdf). The incentive value used was $850/kW. The REG incentives are from the 2019 approved values that were in effect between April 1, 2019 and March 31, 2020 (See http://www.ripuc.ri.gov/eventsactions/docket/4892-DGBoard-NGrid-2019REG-Ord23827%205-7-2020.pdf, Appendix A). We used the small-scale solar incentive of $0.2845/kWh for a duration of 15 years.

[16] For more information on all current solar policies, see Appendix C. Current Solar Policies in Rhode Island.

Next, for each of these payback periods, we used a market penetration curve from a 2016 NREL report to translate the payback period into an expected statewide adoption rate.[17] For example, under this curve, a payback period of 5 years corresponds to about 60 percent of homeowners adopting solar, whereas a payback of 10 years corresponds to an adoption rate of 25 percent (Figure 7). Using this market penetration curve, our lowest calculated payback periods of 7.1 equates to a market penetration of 19 percent, while our highest calculated payback period of 13.0 years corresponds to a market penetration of 40 percent.

Figure 7. Residential solar market penetration relative to payback period



Next, for each municipality, we scaled both the low and high estimates of market penetration by a scalar corresponding to the difference between each town or city's median income and the statewide median income. This allowed us to estimate variations in market penetration by municipality. Finally, the resulting level of market penetration was applied to the municipality-specific technical potential value calculated in the previous section to determine both a low and a high estimate for economic potential for each municipality.[18]

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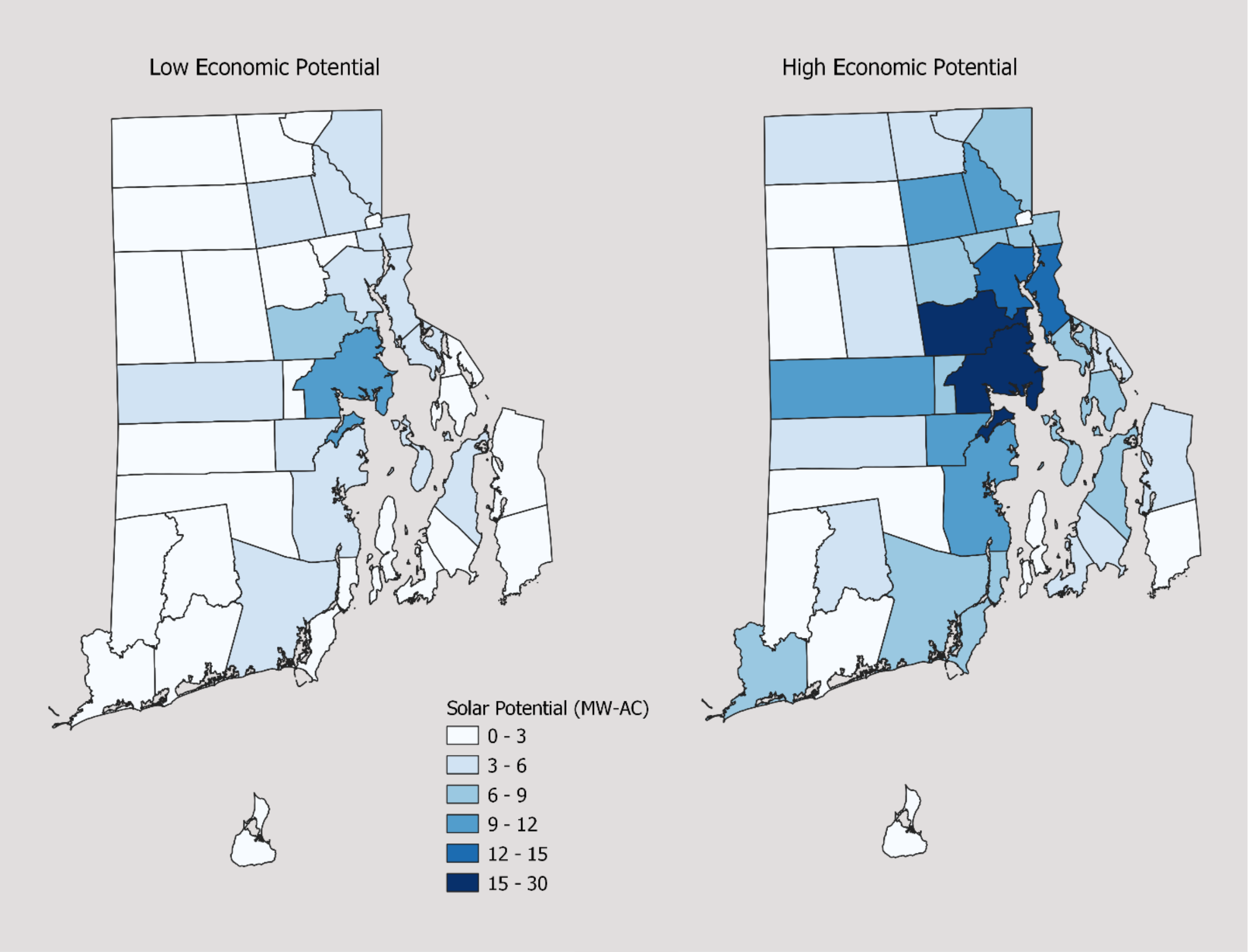
[17] National Renewable Energy Laboratory. 2016. The Distributed Generation Market Demand Model (dGen): Documentation. Page 23. Available at: https://www.nrel.gov/docs/fy16osti/65231.pdf.

[18] REF provides an upfront incentive payment, but this payment does not cover the cost of the entire PV system. REG does not provide an upfront incentive payment. The derived payback period is dependent on relative size of solar array to household

Findings

Statewide, our economic potential analysis reduces residential rooftop potential from 2,580 MW (total) to 550 MW (technical) to 110–250 MW (economic). Even at the lowest end of economic analysis, all 39 municipalities are estimated to at least some economical potential for residential rooftop solar. Note that not all of this economic potential may be realized. There are other factors that may impact whether or not solar is developed, including education and outreach, access to capital or financing, and disconnects between available solar incentives and renting.[19]

Figure 8. Map of residential rooftop low and high economic potential by municipality (MW)



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load. This analysis assumes median solar arrays and household load. All potential numbers are calculated independently from requirements under current net metering that limits generation to 125 percent of onsite usage for non-virtual net metered projects. All potential numbers are calculated independently from a municipality's eligibility to participate in current state programs

[19] See NREL's website on "Low- and Moderate-Income Solar Policy Basis" at https://www.nrel.gov/state-local-tribal/lmi-solar.html for more information on barriers that may impede solar adoption.

Estimated annual generation

The estimated annual generation (measured in GWh) for total, technical, and economic potential on rooftops was calculated using an NREL-derived capacity factor of 15 to 16 percent.[20] Compared to capacity potential (measured in MW), which describes the peak amount of power that is possible to output at any one point in time, annual generation describes the total amount of electricity that is available to be produced over the course of an entire year.

The aggregated technical potential across all rooftop categories totals 1,130 GWh. As a point of reference, according to ISO New England, wholesale electricity load for Rhode Island in 2020 totaled 7,826 GWh.[21] Although this technical potential represents 14 percent of the current electricity load for Rhode Island, the ability for solar to completely meet in-state electricity demand is limited by timing of generation and demand, hosting availability (see Chapter 5), and other factors.

Table 5. Estimated annual rooftop generation (GWh)

Subcategory	Total potential	Technical potential	Economic potential
Residential Single Family	2,740	580	120-280
Residential Multifamily	630	140	20-50
Commercial	480	170	-
Industrial	310	150	-
Municipal	60	20	-
Mixed Use	60	20	-
Other	180	60	-
Total	**4,470**	**1,130**	**140-330**

Costs

Table 6, Table 7, and Figure 9 summarize the estimated historical costs of rooftop solar, for both residential and non-residential installations. Costs are presented using two different metrics:

- Dollars per Watt, direct current ($\$/W_{DC}$), a metric commonly used in the solar industry to compare the installed costs of solar across different facilities
- Dollars per megawatt-hour, alternating current ($\$/MWh_{AC}$), a metric that is commonly used to compare the lifetime, levelized costs of different types of generating facilities (e.g., solar, wind, and natural gas combined cycle).[22] Calculation of a $\$/MWh_{AC}$ cost

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[20] Capacity factors are represented as a range depending on building size (small, medium, and large), and building location (e.g., rural, urban, suburban). Capacity factors were estimated using Gagnon, P., R. Margolis, J. Melius, C. Philips, and R. Elmore. 2016. “Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment.” National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy16osti/65298.pdf

[21] ISO New England’s 2020 CELT Forecast, available at https://www.iso-ne.com/static-assets/documents/2020/04/forecast_data_2020.xlsx. Note that this number refers to net demand, after taking into account the impact of existing energy efficiency and distributed PV resources.

[22] Data on REF costs provided by Rhode Island Commerce Corporation in Fall 2019; data on REG costs provided by National Grid in Spring 2020. All other costs are based on REG data provided by National Grid.

requires assumptions about capacity factors, DC-to-AC conversion ratios, operating and maintenance costs, and financing costs which may vary in reality for each solar installation.[23]

For example, the median cost of residential solar installations is \$4.15/W$_{DC}$, or \$208/MWh$_{AC}$. Conversely, non-residential rooftop solar installations are slightly cheaper, with a median cost of \$3.07/W$_{AC}$ and \$153/MWh$_{DC}$. In addition to median values, we also report the following percentiles—5th, 20th, 80th, and 95th—in order to indicate the range of solar costs reported by the REF and REG programs. All costs only include projects installed since 2018, and all costs are presented in 2018 dollars.

Table 6. Upfront costs of solar, rooftops (\$/W$_{DC}$)

Subcategory	Minimum (5%)	Low (20%)	Mid (50%)	High (80%)	Maximum (95%)
Residential	\$2.80	\$3.27	\$4.15	\$5.00	\$5.91
Non-residential	\$0.07	\$2.42	\$3.07	\$3.64	\$3.99

Table 7. Lifetime levelized costs of solar, rooftops (\$/MWh$_{AC}$)

Subcategory	Minimum (5%)	Low (20%)	Mid (50%)	High (80%)	Maximum (95%)
Residential	\$146	\$168	\$208	\$247	\$288
Non-residential	\$17	\$124	\$153	\$179	\$195

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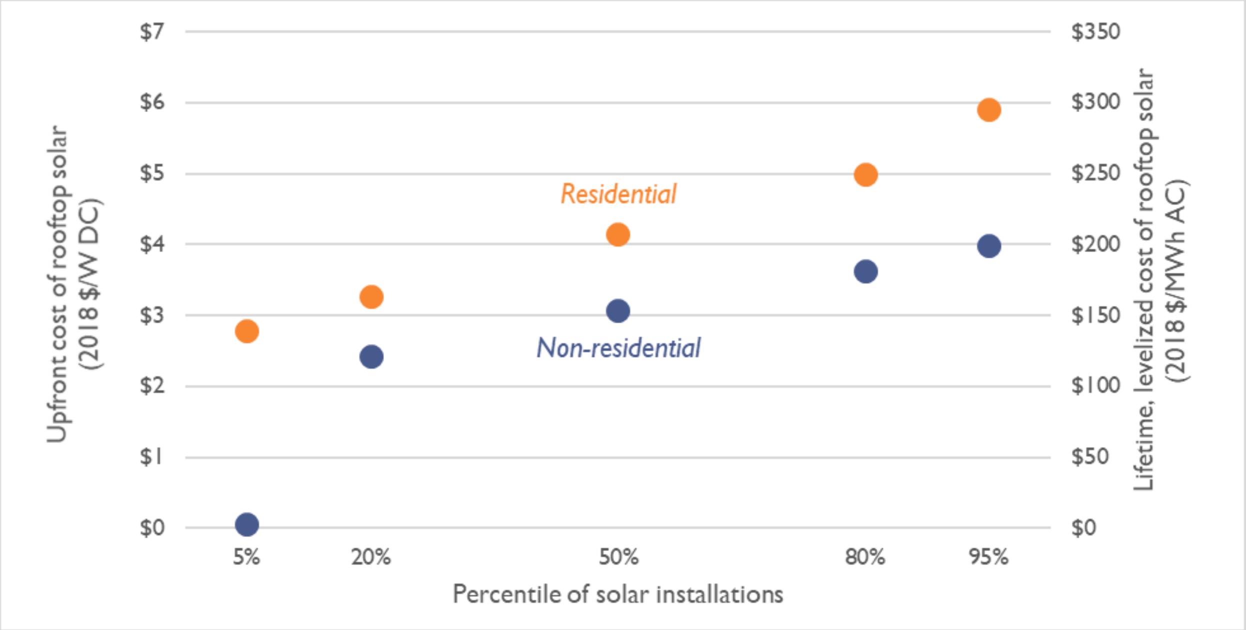
[23] For rooftop solar, we assume a 15 percent capacity factor (based on data from NREL's 2016 report "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment"), an 87 percent DC-to-AC conversion rate, based on data provided to Synapse by National Grid, a fixed operating and maintenance cost of \$18/kW for non-residential solar and \$24/kW for residential solar (based on data from NREL's 2019 "Alternative Technology Baseline" study, available at https://atb.nrel.gov/electricity/2019/data.html), a variable operating and maintenance cost of \$0/kWh for non-residential solar and \$0/kWh for residential solar (based on data from NREL's 2019 "Alternative Technology Baseline" study), and a financing cost of 5 percent (based on data from NREL's 2019 "Alternative Technology Baseline" study).

Figure 9. Costs of rooftop solar in Rhode Island 2018-2019



Note: Each point on this figure represents the cost for rooftop solar installations in Rhode Island for a particular set of installations. For example, the upper-left point indicates that 5 percent of all residential solar installations cost less than $2.80 per W_{DC} *(or $146 per* MW_{AC}*). Meanwhile, the lower-right point indicates that 95% of all non-residential solar installations cost less than $3.99 per* W_{DC} *(or $195 per* MWh_{AC}*). The lifetime, levelized cost considers both the upfront cost, as well as assumptions about capacity factors, DC-to-AC conversion ratios, operating and maintenance costs, and financing costs which may vary in reality for each solar installation.*

Avoided emissions

To calculate the avoided emissions associated with each category of solar PV, we used U.S. EPA AVoided Emissions and geneRation Tool (AVERT). AVERT uses statistical dispatch of individual power plants to estimate regionally, hourly electric power sector impacts resulting from energy efficiency and renewable energy programs. We applied distributed solar PV carbon dioxide (CO_2) emissions factors from AVERT's Northeast region to the estimated generation values to calculate the avoided emissions. In total, we estimate that the 850 MW rooftop potential is capable of avoiding about 737,800 metric tons of CO_2, or 0.7 million metric tons ($MMTCO_2$).

Table 8. Avoided emissions, rooftop technical potential (metric tons CO_2)

Subcategory	Avoided GHG emissions
Residential Single Family	377,600
Residential Multifamily	89,900
Commercial	110,100
Industrial	96,400
Municipal	15,400
Mixed Use	9,700
Other	38,500
Total	**737,600**

Caveats and data limitations

A major caveat for the rooftop solar potentials is the use of building footprint area as a proxy for rooftop area. The area of a rooftop may be smaller than the building footprint, therefore our estimates may underestimate the actual total potential for rooftop solar. Furthermore, due to data constraints, we did not consider the structural integrity or age of the buildings—two important aspects of a building when siting solar on a rooftop. Accounting for structural integrity or building age would reduce the amount of overall technical potential, as some buildings may be unable to structurally support the weight of solar panels. In addition, or perhaps instead, it could impact economic potential—structural upgrades may be physically possible, but could increase costs, leading to fewer installed MW.

Several caveats exist relating to the coding of zoning data:

- The building categories (e.g., single family residential, commercial, etc.) were determined based on the zoning data provided by each municipality in the state. Because each municipality's zoning data are coded differently, the extrapolation of the zoning data into broader categories is only as accurate as the data provided. One notable example of this is the way in which multifamily buildings are zoned—some municipalities may consider a two-family building to be multifamily, while others may consider it an attached single family (as an example). This is unlikely to substantially impact the sum of the overall total or technical potential, but does lend uncertainty as to how much total or technical potential is in one category of building versus another (e.g., residential single family vs. mixed use).

- Zoning and parcel data are of different vintages, and in some cases vintage information does not exist. Data with more recent vintages may be more up-to-date, while older data may include zoning designations that are no longer correct.

- Out of the 39 municipalities in Rhode Island, Synapse received zoning and parcel data from 34. For the municipalities for which we did not receive zoning and parcel data, we used U.S. Census data (including housing density, median income, and population) to identify similar municipalities to apply known zoning category breakdowns.

We assume the same capacity factors to convert each potential category capacity (MW) into potential energy (GWh). However, these capacity factors assume that solar is sited on the feasible parts of roofs, rather than the parts deemed infeasible by NREL (e.g., parts of roofs that contain HVAC equipment, are shaded, or have complex rooftop geometry). As a result, it is likely that the total potential energy is lower than what is estimated here.

3. GROUND-MOUNTED SOLAR

We analyzed potentials for four categories of ground-mounted solar: landfills, brownfields, gravel pits, and Commercial and Industrial (C&I) parcels. Each of these categories was analyzed using a different methodology, although each category shares some similarities in data sources and approaches. Each of the following discussions details the overarching methodology used to calculate solar potential followed by sections that describe the aggregate results of costs, generation, and emissions for all ground-mounted solar categories.

Table 9. Summary of potentials and costs, ground-mounted

Subcategory	Total potential (MW)	Technical potential (MW)	Technical potential (GWh)	Technical potential avoided GHG emissions (MT CO2)
Landfills	430	30 – 90	120 – 450	26,800 – 95,700
Brownfields	1,060	260 – 650	450 – 1,120	273,000 – 686,000
Gravel pits	150	30 – 90	50 – 160	29,300 – 96,300
Commercial and Industrial	9,040	1,160 – 4,600	2,000 – 7,930	1,200,000 – 4,830,000
Total	**10,680**	**1,480 – 5,430**	**2,620 – 9,660**	**1,530,000 – 5,710,000**

3.1. Landfill solar potential

Based on the dataset used, there are 63 landfills in Rhode Island (see Figure 10. 33 municipalities have at least one landfill, whereas 6 municipalities do not. In aggregate, we estimate the aggregate technical potential of landfills to be 70 to 260 MW (Table 10 and Figure 11).

Figure 10. Map of landfill counts by municipality

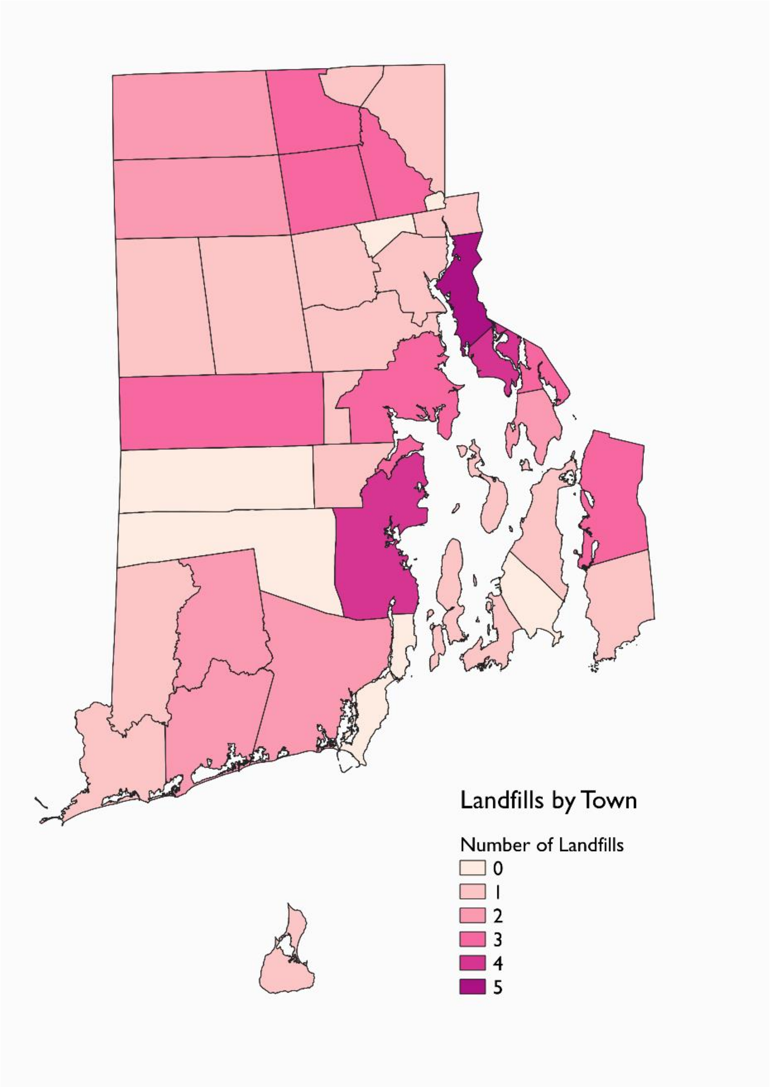
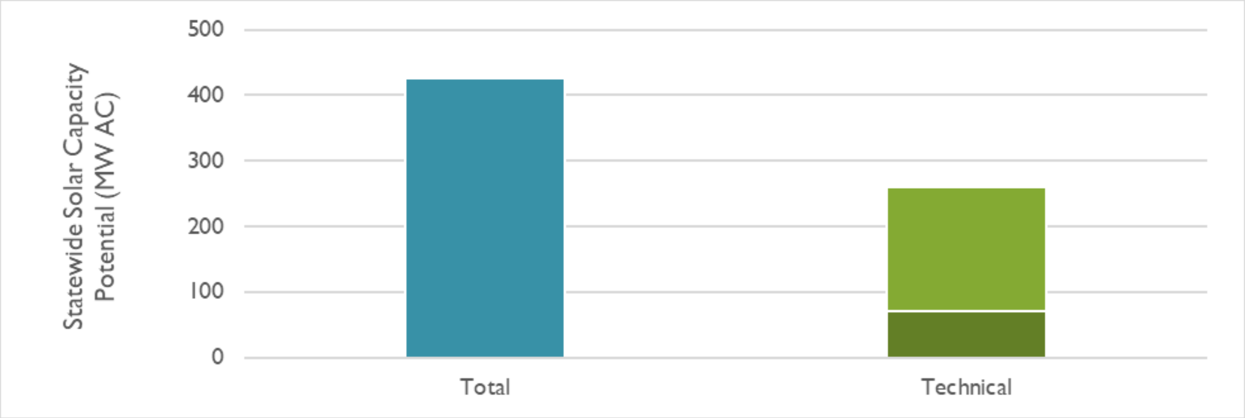


Table 10. Summary of landfill solar potential

Subcategory	Total potential (MW)	Technical potential (MW)	Avoided GHG emissions (MT CO2)
Landfills	430	70 – 260	74,500 – 273,500

Figure 11. Landfill solar PV total and technical potentials (MW)



Total potential

Total potential refers to the entire quantity of solar possible, less the solar capacity currently installed through Fall 2019.

Data and methods

The area of all landfills in Rhode Island was calculated using Geographic Information Systems (GIS) software. First, researchers at University of Rhode Island (URI) provided an existing geospatial dataset of Rhode Island landfills, with one polygon for each of the 63 known landfills in Rhode Island.[24] Using a dataset from RIGIS on building footprints (used above in rooftop potential analysis), we removed any building footprints from the landfill polygons and calculated the remaining area for each landfill polygon. These area values were then multiplied by an NREL-derived value describing the number of MW that can be built per square kilometer of land.[25]

Findings

The total solar potential on all landfills in the state is approximately 430 MW. The Town of Richmond, which has two landfills, has the highest total potential at 60 MW (Figure 12).

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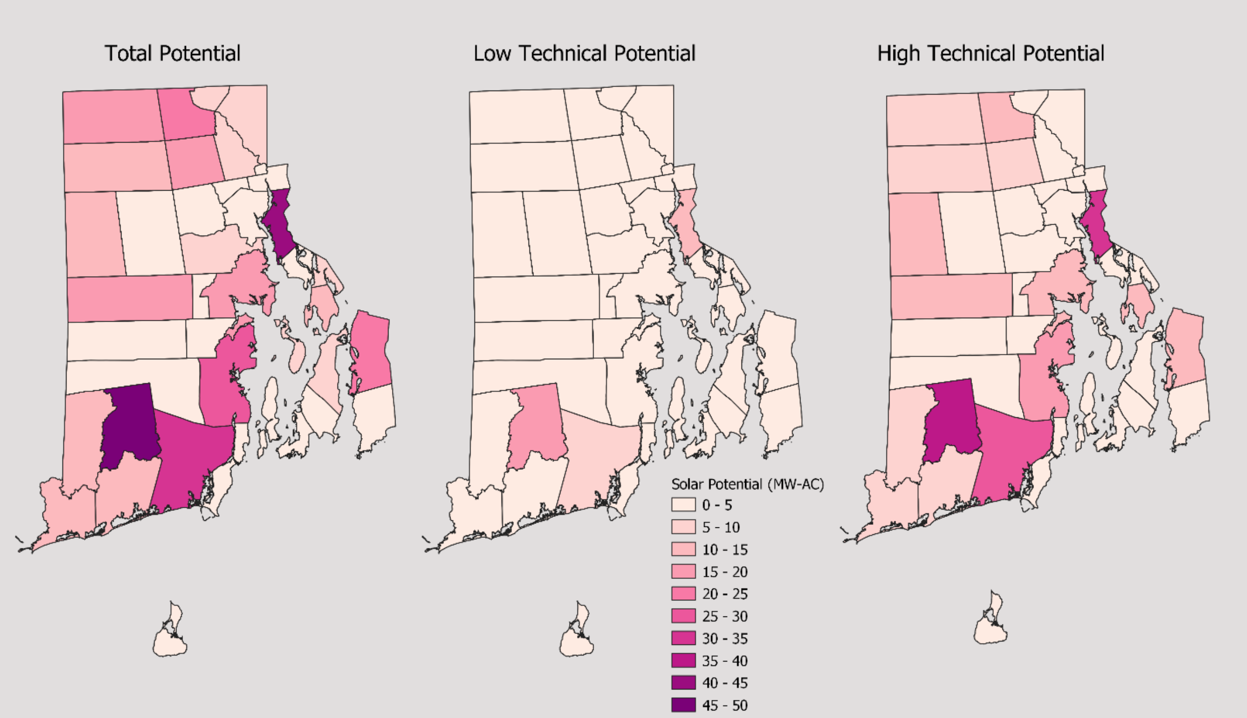
[24] The existing geospatial data was provided by researchers at the University of Rhode Island, who conducted a landfill solar potential study in 2011. For more information, see Boving, T., P. Cady, D. Musher, T. Davis, and C. Damon. 2011. "Rhode Island Renewable Energy Siting Partnership Final Report, Volume 2 Technical Reports, RESP Technical Report #8." University of Rhode Island. Available at https://www.crc.uri.edu/download/resp_volume_2_final.pdf. .

[25] See Brown, A., P. Beiter, D. Heimiller, C. Davidson, P. Denholm, J. Melius, A. Lopez, D. Hettinger, D. Mulcahy, and G. Porro. 2016. "Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results." National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy15osti/64503.pdf. NREL estimates a utility-scale solar PV potential in the United States of 27.9 GW_{AC} over 715.9 square kilometers of land. This yields an installation density of 39 MW_{AC} per square kilometer for Utility for fixed systems.

Figure 12. Maps of total, low technical, and high technical potentials of landfill solar (MW)



Technical potential

Technical potential is a subset of total potential that includes only areas that are suitable for solar development.

Data and methods

Technical potential for solar PV on landfills is defined as the amount of solar PV that can be built given restrictions on certain types of land and physical qualities of the land that increase the installation cost of the panels. We calculated technical potential by trimming the total potential area of landfills in GIS with the following geographic restrictions:

- **Building setbacks**: Solar panels are typically setback from buildings in order to avoid shading and facilitate site maintenance. While these type of setbacks are highly site-specific, for purposes of simplicity, our analysis assumed a building setback of 50 feet for any landfills that have a building on co-located on the parcel (see sidebar for more information on estimating setbacks). This setback estimate was developed through surveys and telephone conversations with Rhode Island's town planning agencies and solar developers.

- **Property edge setbacks**: Solar PV panels may not be able to be built up to the edge of the property line. Each of Rhode Island's 39 municipalities has its own individual zoning ordinances governing what types of facilities can be built within a parcel, and where. However, for purposes of simplicity, we examined two different setback possibilities: 50 ft and 375 ft (see sidebar for more information). This setback range was developed through surveys and telephone conversations with Rhode Island's town planning agencies and solar developers.

- **Land-use restrictions:** Solar PV panels cannot be built on certain types of land, including water bodies (e.g., rivers, ponds), rock outcroppings, and wetlands. We also reviewed each landfill using satellite data from Google Maps to exclude any areas that were obviously no longer suitable for solar (e.g., baseball fields, existing solar, and more). Where a landfill overlaps with any of these types of land, the area was removed from the analysis.

- **Land slope**: LIDARdata was converted into slope data for each landfill in the state.[26] We removed land with a slope greater than 10 degrees because solar installation is assumed to be impractical on steeper slopes.[27]

Estimating setbacks

A "setback" refers to the smallest distance to a boundary at which ground-mounted solar may be constructed. We estimated two different setback types: setbacks from buildings, and setbacks from property lines.

First, to estimate setbacks from buildings, we assumed the average building was 20 feet in height (equivalent to a 2-story house with 10-foot tall stories). According to input from solar developers, solar facilities are typically sited at a distance of at least 3X the height of a nearby building when sited North-South relative to the building. When located East or West of a building, this metric is 2X. We assumed that half of solar installations will be built North-South, and half will be built East-West (in reality, solar installations will be built in many directions relative to buildings). This assumption translates into a height multiplier of 2.5X. We then multiplied 2.5 by 20 feet to get a building setback of 50 feet.

Second, we estimated a range of setbacks for property lines. At the low end, we used input from solar developers indicating that properties located next to commercial or industrial parcels may only need to be setback 50 feet to arrive at our low estimate. At the high end, we relied on input from solar developers that properties located next to residential parcels must be set back 200 feet. We also assumed the existence of 70 feet tall trees around the edge of the property that require an additional setback. Using the same 2.5 ratio from the building setback, we added another 175 feet to the total required set back, adding to a total 375-foot setback.

The setbacks from buildings and parcel lines are estimates based on existing literature and input from solar developers. However, the geography and tree locations vary, and municipalities may have individual setback requirements that are different from the ones we have defined here.

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[26] Rhode Island Geographic Information System. Spring 2011 Statewide Lidar – DEM in UTM. Available at: http://www.rigis.org/pages/2011-statewide-lidar-utm-dem.

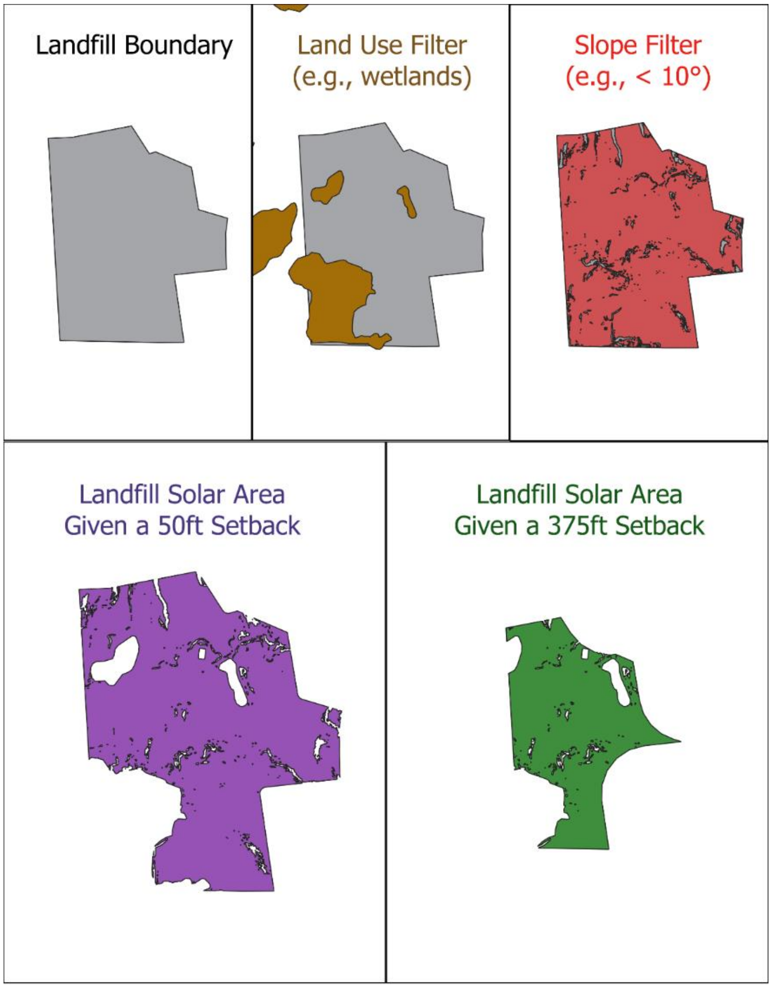
[27] This threshold was selected based on conversations with solar developers in Rhode Island. For the purposes of defining technical potential, the practicality of building on steeper slopes is based on expense. Surveys of solar developers suggested that their projects were unlikely to see cost increases or changes to feasibility as long as land slopes were lower than 10 percent. However, construction on steeper land may be possible at higher costs, meaning that this technical potential may be an underestimate.

Due range in likely property setbacks across Rhode Island's municipalities, we calculated two technical potentials for landfills—a low technical potential area (using the 375ft setback) and a high technical potential value area (using the 50ft setback).

Findings

Figure 13 illustrates the order in which the technical restrictions were applied to the original landfill data, as follows: property and building setbacks, land-use restrictions, and slope. The technical filters reduce the statewide solar PV analysis to a range of 70 to 260 MW. Richmond—the municipality with the largest landfills by area—has the highest technical potential at 20 to 40 MW.

Figure 13. Schematic of the approach to calculating area for landfill solar technical potential



Caveats and data limitations

The following caveats apply to the landfill analysis:

First, the original landfill dataset and polygon shapefile from URI is from 2005 and has not been updated. As such, there may be some newer landfills (or expansions of current landfills) that are excluded from our analysis. Further, some of the re-use information may be out of date (e.g., whether the landfill is currently being used for athletic fields, parks, transfer stations).

Second, we assume the URI polygons of Rhode Island landfills accurately represent the entire property of each landfill; therefore, we made no changes to those boundaries. Given the large number of landfills (over 60), we were unable to manually check the accuracy of the available metadata and polygon shapes.

Third, we consider all landfills to be suitable for solar development, regardless of their capping status. Landfills must be capped before solar PV can be installed; therefore, already capped landfills are likely to be better suited for PV than uncapped landfills, or represent sites with lower development costs, all else being equal.

Fourth, only landfill area that is less than 10 degrees sloped is considered to be feasible for solar under our definition of technical potential. Solar installations may be possible at locations with steeper slopes, which means that our technical potential would be an underestimate.

Finally, there are currently installed solar facilities at landfills in Rhode Island, as well as solar facilities that are currently being installed at landfills at the time of this report's publication. However, data provided from RI Commerce Corporation and National Grid does not identify which of the thousands of facilities are sited on landfills. Using satellite data from Google Maps, we removed areas that clearly feature solar facilities; however, this satellite data was last updated 2018 and may be outdated. For this reason, our derived values for potential are likely to be an overestimate for landfill locations that presently have installed solar.

3.2. Brownfield solar potential

According to the Rhode Island Department of Environmental Management (RI DEM), brownfields are properties where expansion, redevelopment, or reuse might be complicated by the presence (or potential presence) of a hazardous substance, pollutant, or contaminant.[28] Statewide, we estimate the technical potential for solar on remediated brownfields to be 260 to 650 MW (see Figure 14, Table 11, and Figure 15).

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[28] *Reinvesting in Rhode Island's Brownfields*. Rhode Island Department of Environmental Management. 2018. http://www.dem.ri.gov/brownfields/.

Figure 14. Number of brownfields in Rhode Island by municipality

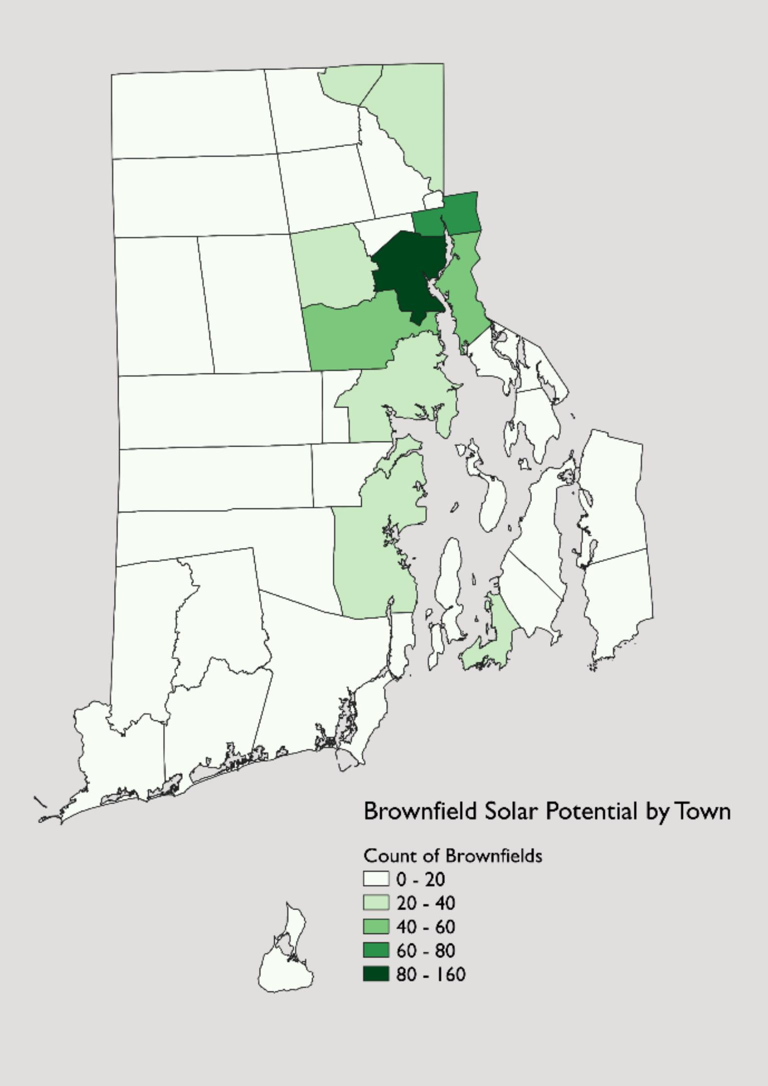
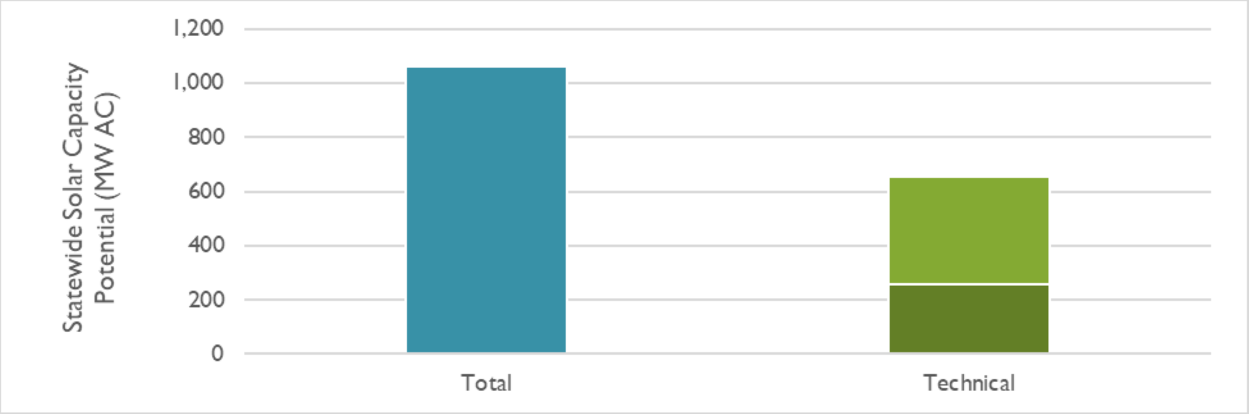


Table 11. Summary of brownfield solar potential

Subcategory	Total potential (MW)	Technical potential (MW)	Avoided GHG emissions (MT CO2)
Brownfields	1,060	260 – 650	273,000 – 686,000

Figure 15. Brownfield solar PV total and technical potentials (MW)



Total potential

Total potential refers to the entire quantity of solar possible, less the solar capacity currently installed through Fall 2019.

Data and methods

First, RI DEM provided a dataset listing over 700 known remediated brownfield sites in the state of Rhode Island. This dataset includes the brownfield name, address, municipality name, and area.[29] We cleaned this address data and successfully matched about one-third of all brownfields to parcels in the town/city geospatial data. Using the addresses in the supplied DEM dataset, along with addresses in parcel data provided by cities and towns, we were able to match over 230 of those sites to known parcels.[30] For those brownfields that didn't match to an address, we manually reviewed satellite and parcel data and created additional polygons for the 14 largest brownfields. To estimate total potential, we multiplied the total area of brownfield sites from the DEM dataset by the ground-mount installation MW-per-square-kilometer value used in the landfill analysis. Then, we subtracted the MW capacity of existing solar facilities sited at brownfields.

Findings

Across the state, there is approximately 1,060 MW of solar PV total potential in Rhode Island (Figure 16). The Town of Charleston has the highest total brownfield potential at 182 MW.

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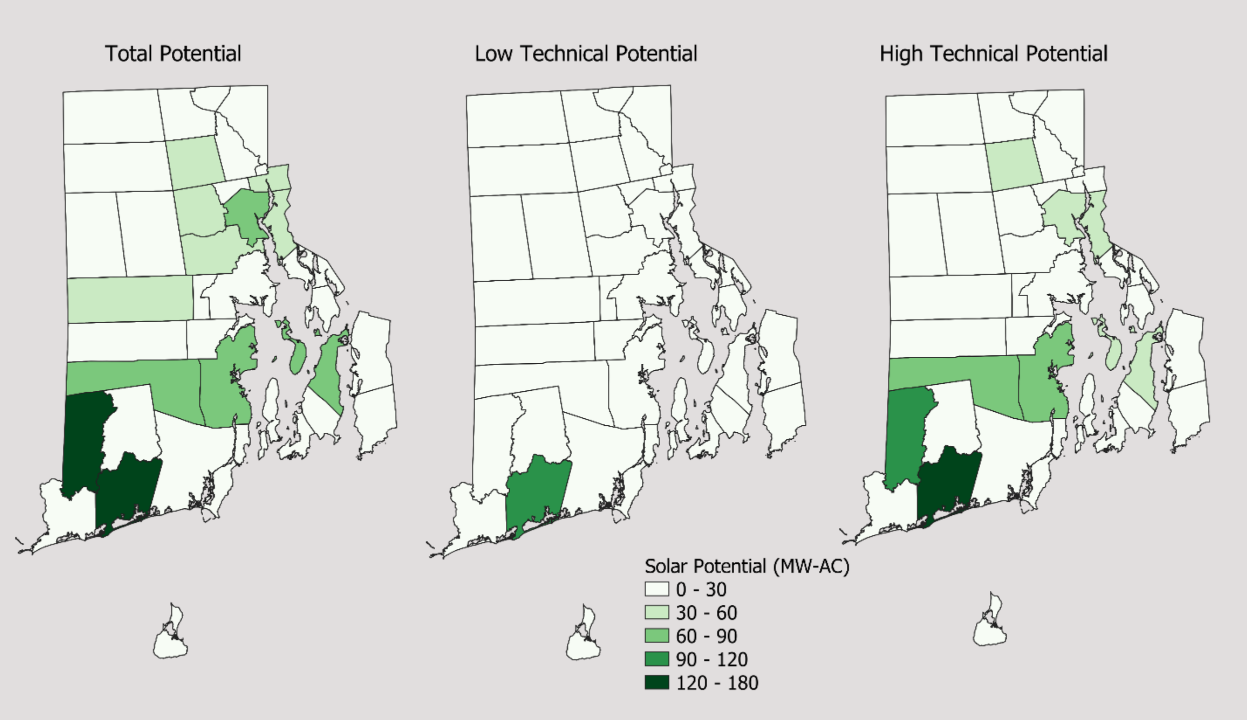
[29] RI DEM. (2019, September 16). *Remediated Sites – Potential Solar*. Available at http://www.dem.ri.gov/programs/wastemanagement/inventories.php.

[30] The remaining 500 sites had generic, unspecific addresses that did not match to a parcel (i.e., addresses without a street number). We also attempted to manually match the largest 15 remaining unmatched brownfield sites. However, we were only able to manually code four sites, which were then added to the GIS analysis.

Figure 16. Map of brownfield solar total, low technical, and high technical potential by municipality (MW)



Technical potential

Technical potential is a subset of total potential that includes only areas that are suitable for solar development.

Data and methods

We then analyzed these parcels in GIS. We applied most of the same technical potential filters that were applied to landfills: setbacks from the edge of the landfill property (50 and 375 ft), a setback from any buildings on the property (50 ft), and land-use restrictions.[31] As with landfills, this process yielded both a low end and a high end for technical area. Because of discrepancies in the area value described by DEM and the values for matched parcels using data provided by towns and cities, and because the matched parcels analyzed in GIS comprised only a third of total brownfields across the state, the ratio of technical area (high and low) was converted into a statewide scalar and multiplied by each municipality's aggregate brownfield area. These resulting high and low technical potential areas were then multiplied by the same ground-mount installation MW-per-square-kilometer value used in the total potential calculation to produce a range of technical potential MW.

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[31] We did not analyze land slope for brownfields due to computational barriers in estimating slope for over 230 discrete parcels. Many brownfield sites are small or were previously the site of economic activity. As a result, they are less likely to feature extreme topological variations that could prohibit solar installations.

Findings

The technical filters reduced the total potential to a range of 260 to 650 MW. The Town of Charleston retains the highest brownfield solar potential even after the technical filters, with a technical potential range of 120 to 170 MW (Figure 16).

Caveats and data limitations

There are several caveats associated with the original dataset obtained from DEM:

- This dataset only contains information on remediated brownfields, rather than all brownfields.
- The dataset is likely not up to date. Because of the large number of brownfield sites, each parcel was not manually analyzed. As a result, our analysis likely includes some sites that have already been repurposed or are planned for redevelopment for some other purpose.
- Only some of the brownfield addresses identified by DEM were able to be mapped. To estimate the total area of all brownfields (including both mapped and unmapped parcels), we relied on DEM's estimates of total area. We then reduced this total area proportional to the areas determined to be technical feasible using GIS software (i.e., total area, reduced to account for account for setbacks and inappropriate land uses). However, this this is only an estimation, and may overestimate the overall area suitable for solar development. For the brownfields that were able to be analyzed using GIS software, we estimated that DEM areas were, on average, 1.4 times larger than the same parcel areas mapped using GIS.

As with all ground-mounted solar estimates, the range of technical potential hinges on the assumed setbacks. See the "Estimating Setbacks" sidebar for more information on how different assumptions for this category could produce changes in technical potential.

We removed any existing solar capacity identified as being installed on a brownfield. However, it is possible that there are other existing solar facilities that are located on a brownfield but are not identified as such. As a result, our analysis may over-estimate solar potential.

3.3. Gravel pit solar potential

A third category of ground-mounted encompasses solar built on sand, stone, and gravel pits in Rhode Island. According to the United States Geological Survey (USGS), there are 13 known such locations in Rhode Island (see Figure 17). Only nine towns and cities have a gravel pit: Coventry, Cranston, Cumberland, Exeter, North Smithfield, Richmond, South Kingstown, Tiverton, and Westerly. In aggregate, we estimate the gravel pit technical potential to be 30-90 MW (see Table 12 and Figure 18).

Figure 17. Map of gravel pits counts by municipality

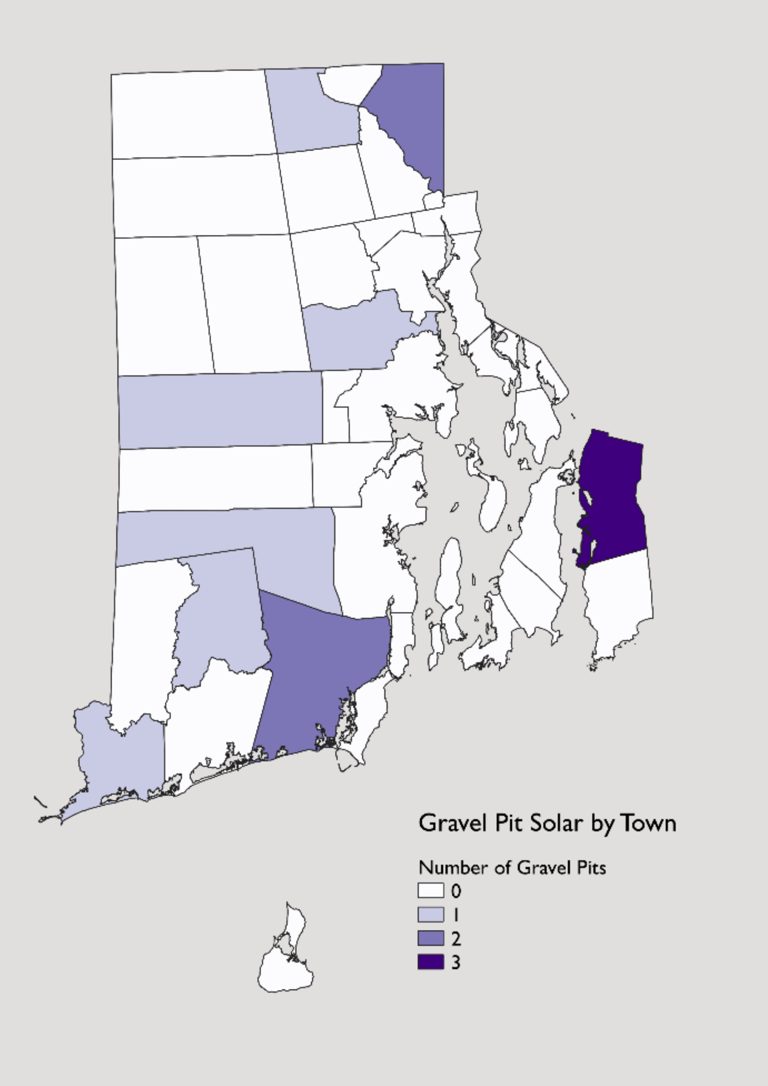
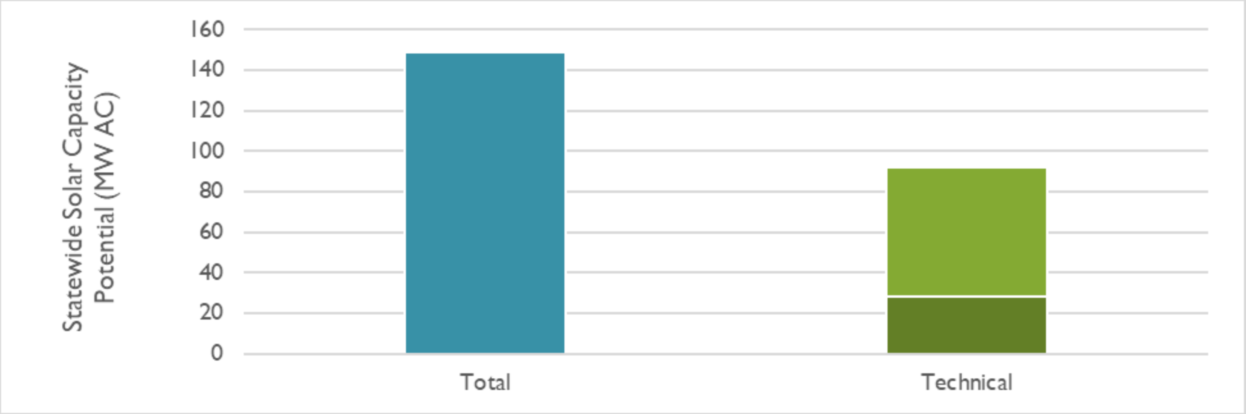


Table 12. Summary of gravel pit solar potential

Subcategory	Total potential (MW)	Technical potential (MW)	Avoided GHG emissions (MT CO2)
Gravel pits	150	30 – 90	29,300 – 96,300

Figure 18. Gravel pit total and technical potentials (MW)



Total potential

Total potential refers to the entire quantity of solar possible, less the solar capacity currently installed through Fall 2019.

Data and methods

A polygon shapefile for gravel pits in Rhode Island does not already exist; therefore, we utilized a point-based shapefile from USGS as a starting point for this analysis.[32] Because of the small number of gravel pits in the point-based shapefile, we were able to create our own polygon-based shapefile. To do so, we used satellite imagery to assist in drawing a polygon around the extent of each gravel pit or mine in the state. As a second step, we merged each of those custom-drawn polygons to any intersecting parcel polygons. The resulting polygons reflect the shape of all parcels within which a gravel pit or mine is located (Figure 19). Total potential (in MW) was then calculated by multiplying the total area of all gravel pits with the NREL-derived value representing the number of MW that can be built per square kilometer.

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[32] United States Geological Survey. 2003. Active mines and mineral plants in the US. Available at: https://mrdata.usgs.gov/catalog/cite-view.php?cite=17.

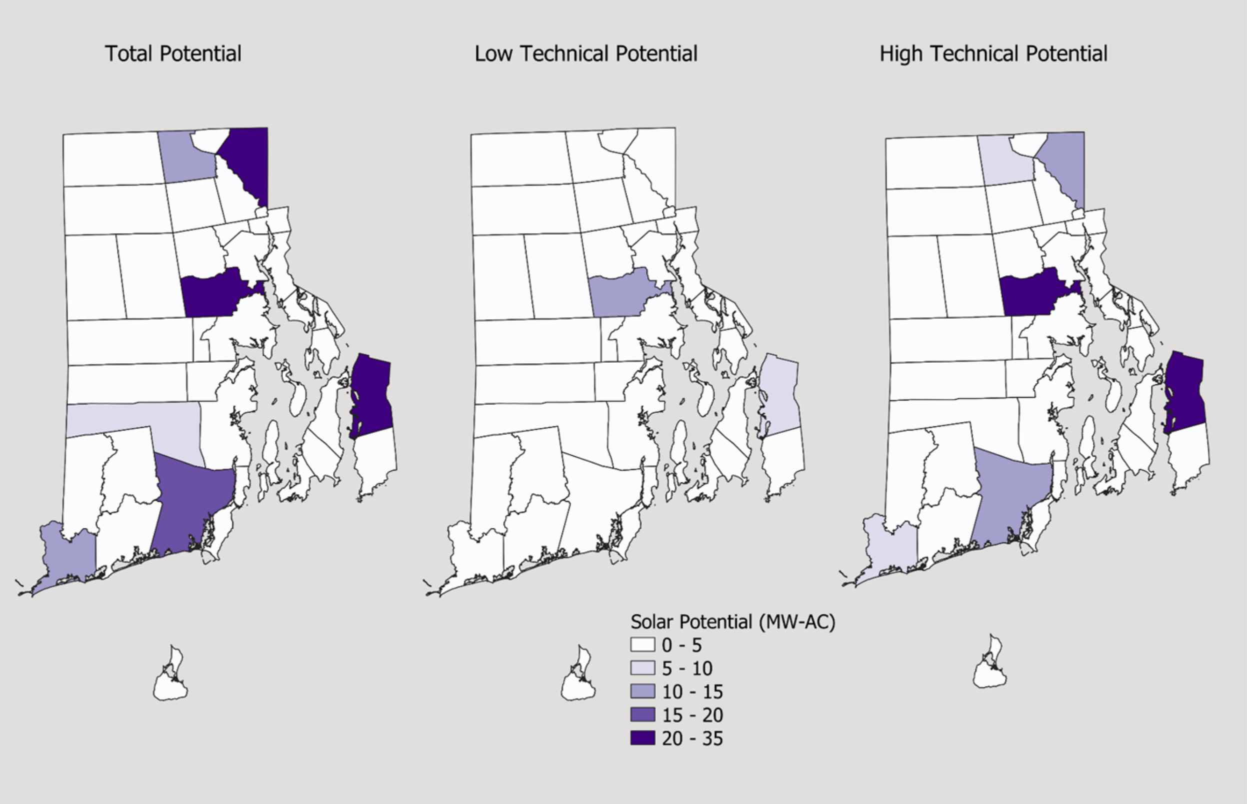
Figure 19. Example gravel pit polygons, after the merge with parcel polygons

Note: Municipality names for each gravel pit are located in the bottom corner of the images.

Findings

We calculate the total solar PV potential of Rhode Island is 150 MW. The City of Cranston has the highest total potential, at 40 MW (see Figure 20).

Figure 20. Maps of gravel pit total, low technical, and high technical solar potentials by municipality (MW)



Technical potential

Technical potential is a subset of total potential that includes only areas that are suitable for solar development.

Data and methods

The process for calculating technical potential for solar at gravel pits followed the same process as landfills. After identifying each of the polygons, we applied the same technical potential filters that were applied to landfills: setbacks from the edge of the landfill property (50 and 375 ft), a setback from any buildings on the property (50 ft), land-use restrictions, and land slope.

As in our landfill analysis, we calculated two technical potential areas for gravel pits—a low technical potential area (using the 375 ft setback) and a high technical potential value area (using the 50 ft setback). The low and high technical potential areas were multiplied by the same MW-per-square-kilometer value used in the total potential analysis, yielding a low and high technical potential estimate for solar PV capacity on gravel pits.

Findings

This process yielded a statewide low technical potential of 30 MW and a statewide high technical potential of 90 MW. The City of Cranston, which had the highest total potential, also had the highest technical potential, with a range of 10 to 20 MW (Figure 20).

Caveats and data limitations

The following caveats apply to the gravel pit analysis:

First, because the original point-based shapefile only included active mines (as categorized by the US Geological Survey in 2003), there might be other inactive gravel pits in Rhode Island not included in this assessment. Because these locations are defined as "active," solar installations may not be possible at some or all parts of the site at this point in time.

Second, because the gravel pit boundary polygons were merged with the boundaries of intersecting parcels, there is a possibility that our resulting polygons over-estimate the geographic area of the gravel pits.

Third, because the LIDAR data used to calculate slope was collected in 2011, there is a possibility that the slope analysis unnecessarily removes parts of gravel pits that have been smoothed. Alternatively, the slope analysis may neglect to filter out steep slopes from pits that have had additional topographical changes since 2011.

Fourth, only gravel pit area that is less than 10 degrees sloped is considered to be feasible for solar under our definition of technical potential. Solar installations may be possible at locations with steeper slopes, which means that our technical potential would be an underestimate.

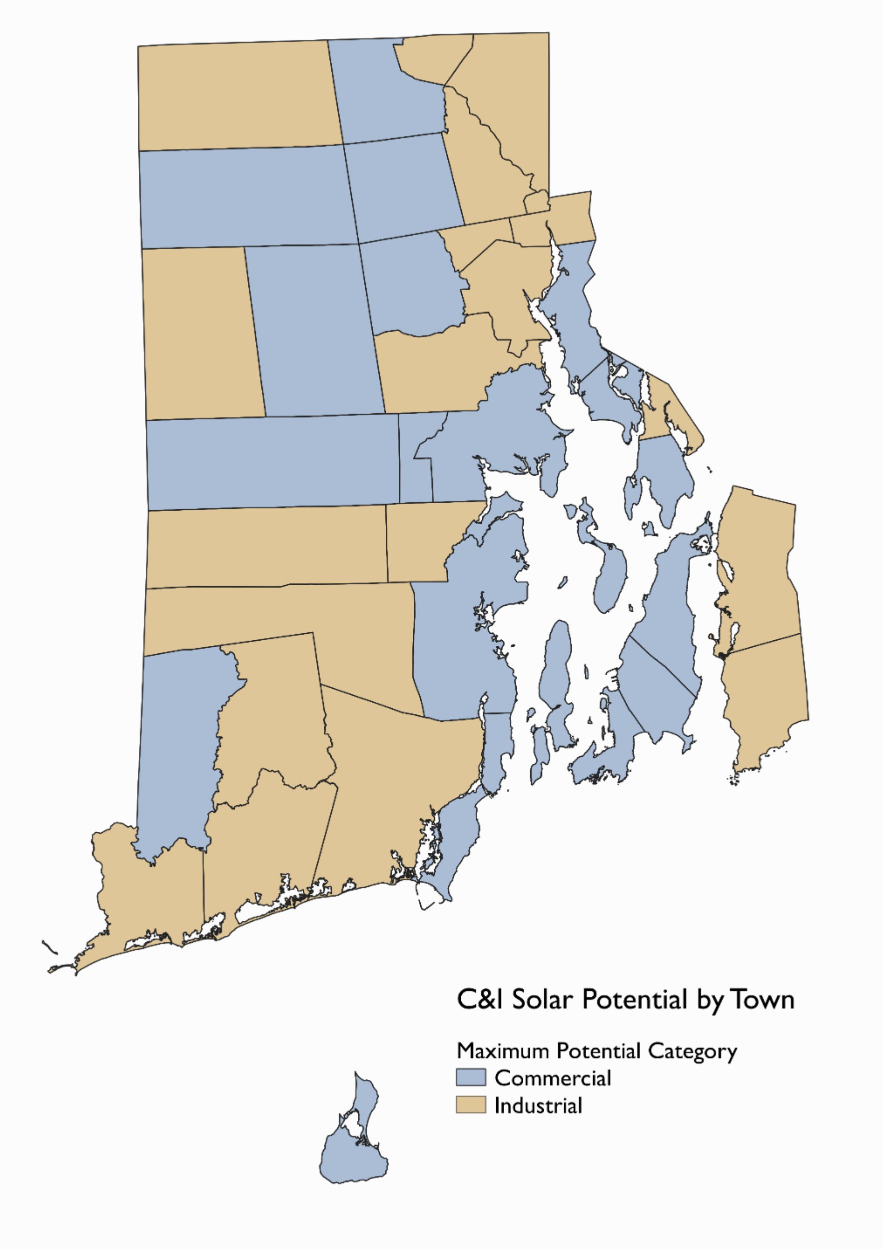
As with all ground-mounted solar estimates, the range of technical potential hinges on the assumed setbacks. See the "Estimating Setbacks" sidebar for more information on how different assumptions for this category could produce changes in technical potential.

3.4. Solar potential at developed and undeveloped commercial and industrial parcels

Commercial and industrial developed and undeveloped parcels (referred to in this report as "C&I parcels") are plots of land that are zoned for commercial or industrial use, or both. By joining zoning and parcel data from each of the towns and cities in Rhode Island, we were able to determine whether each parcel could be categorized as commercial or industrial. Note that this section is only concerned with ground-mounted solar potential on C&I sites and does not include rooftop solar on commercial or industrial sites. Rooftop solar on commercial and industrial buildings is discussed above in Chapter 2. This analysis includes parcels that are both completely undeveloped (e.g., devoid of any existing buildings), as well as parcels that currently have existing buildings in place. For this latter type of parcel, we examined the available area after removing any area associated with building footprints or existing solar installations.

We estimate the aggregate technical potential of ground-mounted solar on C&I parcels to be 1,200 to 4,600 MW (see Table 13 and Figure 22). Figure 21 illustrates whether each municipality has a predominance of commercial or industrial parcels with potential for solar PV. About half of Rhode Island municipalities have a majority of total potential located on commercial buildings, with the other half on industrial buildings. The same is true of the statewide C&I technical potential values: about half of Rhode Island municipalities have a majority of technical potential located on commercial buildings, with the other half on industrial buildings.

Figure 21. Maximum potential category in C&I parcels by municipality



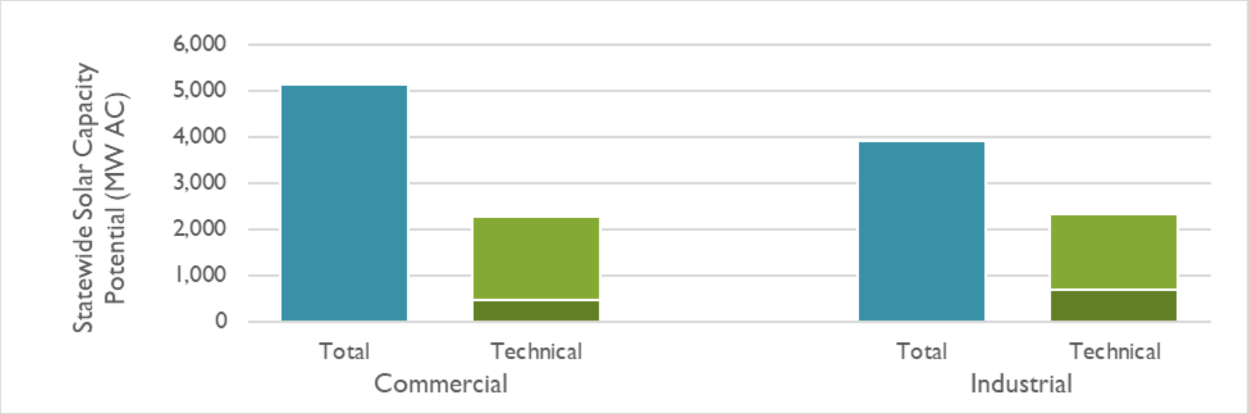
Note: Data described in this figure refers only to ground-mounted commercial and industrial solar facilities. Rooftop-mounted potentials are described above in Chapter 2.

Table 13. Summary of commercial and industrial parcel solar potential

Subcategory	Total potential (MW)	Technical potential (MW)	Avoided GHG emissions (MT CO2)
Commercial	5,120	470 – 2,300	5,372,500 – 2,398,500
Industrial	3,920	680 – 2,300	715,500 – 2,435,300
Total	**9,040**	**1,160 – 4,600**	**1,213,300 – 4,833,800**

Note: Data described in this table refers only to ground-mounted commercial and industrial solar facilities. Rooftop-mounted potentials are described above in Chapter 2.

Figure 22. Commercial and industrial total and technical potentials (MW)



Note: Data described in this figure refers only to ground-mounted commercial and industrial solar facilities. Rooftop-mounted potentials are described above in Chapter 2.

Total potential

Total potential refers to the entire quantity of solar possible, less the solar capacity currently installed through Fall 2019.

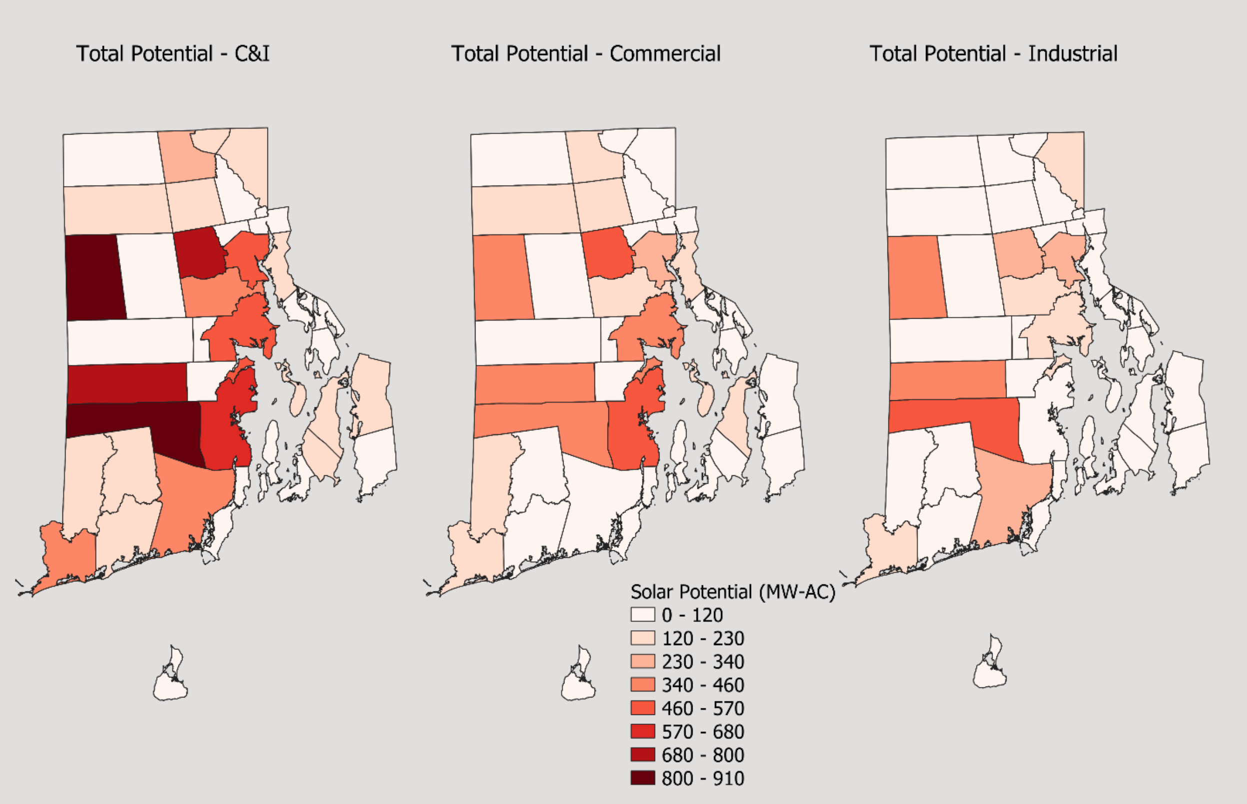
Data and methods

Using zoning and parcel data provided by most cities and towns in Rhode Island, we identified each parcel as being industrial or commercial. The areas of these parcels were then aggregated by municipality and multiplied by an NREL-derived factor describing the quantity of ground-mounted solar able to be installed per square kilometer (see section on Landfill Total potential, above).

Findings

The statewide total potential on C&I parcels is estimated to be 9,000 MW (see Figure 23).

Figure 23. Map of total potential for C&I parcels by building type (MW)



Note: Data described in this figure refers only to ground-mounted commercial and industrial solar facilities. Rooftop-mounted potentials are described above in Chapter 2.

Technical potential

Technical potential is a subset of total potential that includes only areas that are suitable for solar development.

Data and methods

For each commercial and industrial parcel, we applied most of the same technical potential filters that were applied to landfills: setbacks from the edge of the landfill property (50 and 375 ft), a setback from any buildings on the property (50 ft), and land-use restrictions.[33] As with landfills, this process yielded both a low end and a high end for technical area. These resulting high and low technical potential areas were then multiplied by the ground-mount installation MW-per-square-kilometer value used in the total potential calculation to produce a range of technical potential MW.

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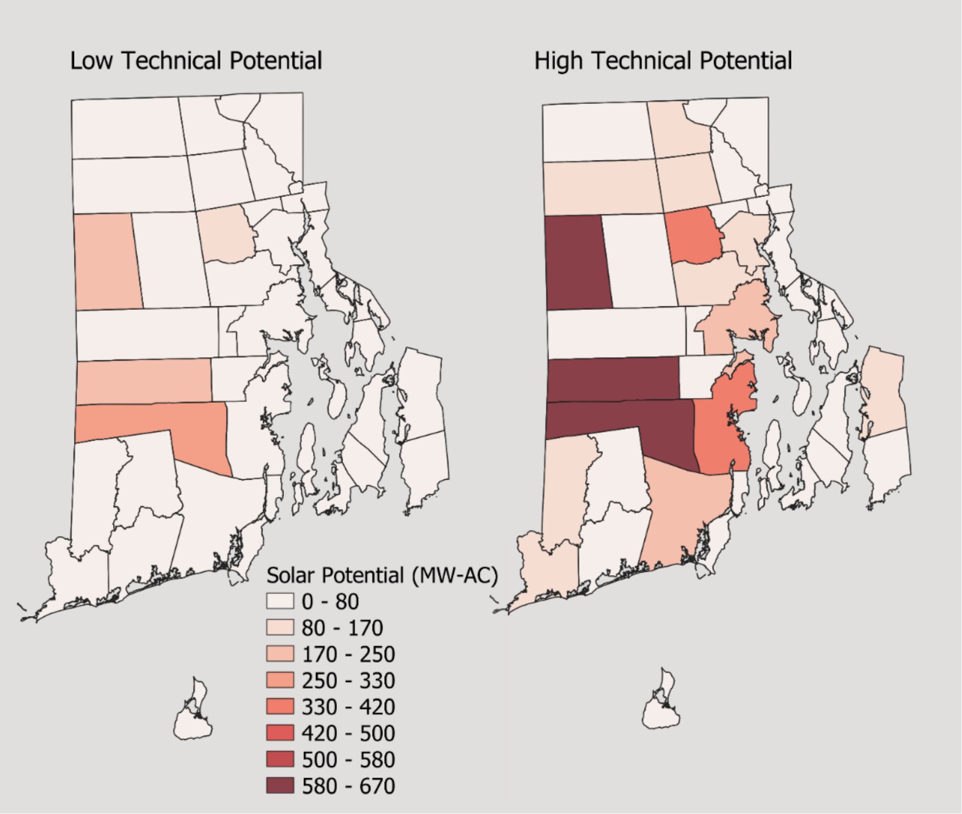
[33] We did not analyze land slope for commercial and industrial parcels due to computational barriers in estimating slope for thousands of discrete parcels.

Findings

The technical potential filters reduce the C&I potential to between 1,200 to 4,600 MW (see Figure 24).

Figure 24. C&I low and high technical potential (MW)



Note: Data described in this figure refers only to ground-mounted commercial and industrial solar facilities. Rooftop-mounted potentials are described above in Chapter 2.

Caveats and data limitations

Commercial and industrial parcels were identified using zoning and parcel data provided by the municipalities. Municipalities' individual zoning data are of different vintages and have different characteristics influencing the results for this category. Out of the 39 municipalities in Rhode Island, Synapse received zoning and parcel data from 34 of the municipalities (see Appendix B for more information). For the municipalities from which we did not receive zoning and parcel data, we used census data to find a similar municipality (based on data on housing density, median income, and population) and used that municipality's C&I parcels per square mile. We then applied this ratio to the municipality without data using that municipality's square mile data. This may mean that potentials for these municipalities may be under- or over-estimated, depending on how similar or different they are to the proxy municipality in terms of zoned area.

We were only able to include one-third of existing brownfield sites in the state using GIS mapping, and were thus able to only remove the brownfields from the C&I category that were correctly coded. This means that there is still some overlap between the C&I parcels we have identified here and other existing brownfields. As a result, we are likely overcounting some amount of existing solar in this category that is actually built on brownfields, and double-counting some amount of total and technical potential that is already counted with brownfields.

Finally, some municipalities may currently have zoning ordinances that govern where ground-mounted solar may be installed. Because of the challenges in comprehensively analyzing all 39 municipalities' most-up-to-date zoning ordinances, these special cases were not considered in our analysis. As a result, technical potentials for municipalities with such ordinances maybe lower than the values estimated in this report.

3.5. Estimated annual generation

The estimated annual generation (measured in GWh) for total and technical potential on ground-mounted solar sites was calculated using an NREL-derived capacity factor of 20 percent for solar facilities in Rhode Island.[34] Capacity factors for ground-mounted facilities are typically higher than rooftop-mounted facilities as it is easier to site ground-mounted facilities for maximum solar output. The aggregated technical potential across all ground-mounted categories totals 2,610 to 9,650 GWh. As a point of reference, according to ISO New England, wholesale electricity load for Rhode Island in 2020 totaled 7,826 GWh.[35] Although the high end of this range exceeds the current electricity load for Rhode Island, the ability for solar to completely meet in-state electricity demand is limited by timing of generation and demand, hosting availability (see Chapter 5), and other factors.

Table 14. Estimated annual ground-mounted generation (GWh)

Subcategory	Total potential	Technical potential
Landfills	730	120 – 450
Brownfields	1,830	450 – 1,120
Gravel pits	260	50 – 160
Commercial and Industrial	15,500	1,990 – 7,920
Commercial	8,800	820 – 3,930
Industrial	6,700	1,170 – 3,990
Total	**18,320**	**2,610 – 9,650**

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[34] Brown, A., P. Beiter, D. Heimiller, C. Davidson, P. Denholm, J. Melius, A. Lopez, D. Hettinger, D. Mulcahy, and G. Porro. 2016. "Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results." National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy15osti/64503.pdf. .

[35] ISO New England's 2020 CELT Forecast, available at https://www.iso-ne.com/static-assets/documents/2020/04/forecast_data_2020.xlsx. Note that this number refers to net demand, after taking into account the impact of existing energy efficiency and distributed PV resources.

3.6. Costs

Table 15 summarizes the estimated historical costs of ground-mounted solar. As with rooftop solar, costs are presented using two different metrics:

- Dollars per Watt, direct current ($\$/W_{DC}$)—a metric commonly used in the solar industry to compare the installed costs of solar across different facilities
- Dollars per megawatt-hour, alternating current ($\$/MWh_{AC}$), a metric that is commonly used to compare the lifetime, levelized costs of different types of generating facilities (e.g., solar, wind, and natural gas combined cycle).[36]

For example, the median cost of ground-mounted solar installations is $\$3.21/W_{DC}$, or $\$122/MWh_{AC}$. In addition to median values, we also report the following percentiles—5th, 20th, 80th, and 95th—in order to indicate the range of solar costs reported by the REF and REG programs. All costs are presented in 2018 dollars.

Table 15. Costs of ground-mounted solar

Cost type	Minimum (5%)	Low (20%)	Mid (50%)	High (80%)	Maximum (95%)
$\$/W_{DC}$	$1.21	$1.71	$3.21	$4.04	$5.52
$\$/MWh_{AC}$	$53	$70	$122	$151	$203

For ground-mounted solar categories, robust cost data for each category was not available, and a typical cost for ground-mounted solar is shown instead. Calculation of a $\$/MWh_{AC}$ cost requires assumptions about capacity factors, DC-to-AC conversion ratios, operating and maintenance costs, and financing costs which may vary in reality for each solar installation.[37]

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[36] Data on REF costs provided by Rhode Island Commerce Corporation in Fall 2019; data on REG costs provided by National Grid in Spring 2020. All other costs are based on REG data provided by National Grid.

[37] For ground-mounted solar, we assume a 20 percent capacity factor (based on data from Brown, A., P. Beiter, D. Heimiller, C. Davidson, P. Denholm, J. Melius, A. Lopez, D. Hettinger, D. Mulcahy, and G. Porro. 2016. “Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results.” National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy15osti/64503.pdf), an 87 percent DC-to-AC conversion rate, based on data provided to Synapse by National Grid, a fixed operating and maintenance cost of $20/kW (based on data from NREL’s 2019 “Alternative Technology Baseline” study), a variable operating and maintenance cost of $0/kWh (based on data from NREL’s 2019 “Alternative Technology Baseline” study), and a financing cost of 5 percent (based on data from NREL’s 2019 “Alternative Technology Baseline” study).

Case Study: Incremental Costs of Ground-Mounted Solar on a Non-Conventional Site

The cost of installing ground-mounted solar on sites like brownfields, landfills, and gravel pits may be higher than similar installations on conventional ground-mounted sites, due to additional permitting and site remediation costs prior to installing the solar panels. To better understand these costs, we used a survey to elicit feedback from solar developers. Revity Energy LLC provided detailed information for one landfill/brownfield combination solar installation.

Table 16 illustrates the estimated incremental costs for several cost categories for the 6.3 MW_{DC} installation at Kilvert Street in Warwick. At this site, incremental costs were estimated to be approximately \$0.13 per W_{DC} above comparable conventional ground-mounted installations. Relative to the Mid (50th percentile) cost estimates described in Table 15, this represents an increase of 4 percent. According to this particular developer, the incremental installation costs are primarily due to additional construction expenses required to prepare the land for the installation of the panels. In addition, this site also has a less ideal slope than other comparable installations. This inhibits optimum solar production, reducing the site's capacity factor by an average of 2 percentage points, relative to comparable conventional sites.

Note that this case study is included in order to provide context on possible incremental costs at non-conventional ground-mounted sites. These costs may not necessarily be representative of all installations at brownfields, landfills, or gravel pits. In addition, solar installations on developed and undeveloped commercial and industrial parcels may not be substantially different or more costly than solar developed on conventional ground-mounted sites.

Table 16. Estimates of incremental costs for brownfield solar installations

Cost Category	Incremental Costs ($/$W_{DC}$)
Permitting/ Professional Fees	**$0.03**
Legal	$0.01
Civil engineering	$0.01
Environmental engineering	$0.01
Survey	<$0.01
Miscellaneous permits	<$0.01
Site Remediation	**$0.03**
Removal of electrical debris	$0.01
Solid waste excavation	$0.02
Landfill cap repair	$0.01
Construction	**$0.05**
Drainage work	$0.02
Ballasted block for cap	$0.02
Cable tray system for cap	$0.01
Developer Burden	**$0.01**
Oversight/ coordination	$0.01
Total	**$0.13**

Source: Revity Energy
Note: Totals may not equal the sum of numbers due to rounding.

3.7. Avoided emissions

To calculate the avoided emissions associated with each category of solar PV, we used U.S. EPA's AVERT model. We utilized distributed solar PV CO_2 emissions factors from AVERT's Northeast region to calculate the avoided emissions associated with rooftop solar PV in Rhode Island. In total, we estimate that the 1,480-5,430 MW ground-mounted technical potential is capable of avoiding between 1.6 and 5.9 million metric tons of CO_2 ($MMTCO_2$).

Table 17. Avoided emissions, all ground-mounted technical potential (metric tons CO_2)

Subcategory	Avoided GHG emissions
Landfills	74,600 – 273,500
Brownfields	272,600 – 685,600
Gravel pits	29,300 – 96,300
Commercial and Industrial	1,213,300 – 4,833,800
Commercial	497,800 – 2,398,500
Industrial	715,500 – 2,435,300
Total	**1,589,800 – 5,889,200**

4. PARKING LOTS

At the time of this report's publication, deployment of solar on parking lots was limited in Rhode Island. Yet it is an area of increasing interest. Parking lot solar is typically mounted on independent raised structures, also known as carports, and is in some ways a hybridization of rooftop solar and ground-mounted solar. By using crowdsourced data as a foundation for this analysis, we were able to develop estimates of total and technical potential for each municipality in the state. In aggregate, we estimate the technical potential of carport solar to be 1,060 MW (see Figure 26, Table 18 and Figure 26).

Figure 25. Map of parking lot quantity by municipality

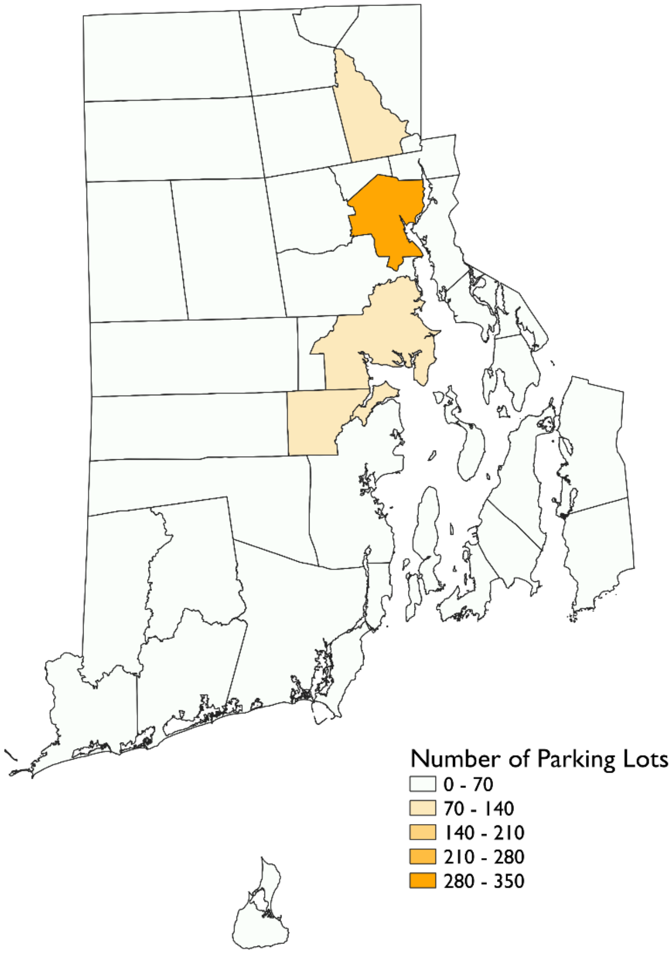
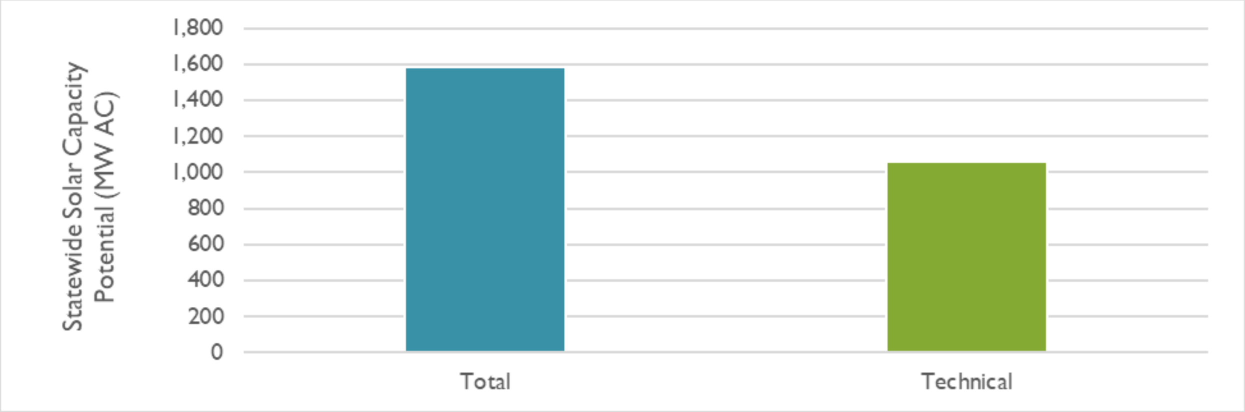


Table 18. Summary of parking lot solar potential

Subcategory	Total potential (MW)	Technical potential (MW)	Technical potential (GWh)	Avoided GHG emissions (MT CO2)
Parking lots	1,590	1,060	1,820	1,191,400

Figure 26. Parking lot total and technical solar PV potential (MW)



4.1. Parking lot solar potential

For the calculation of total and technical potentials in this study, we primarily relied on GIS data from OpenStreetMaps.com[38] and population data from the U.S. Census.[39]

Total potential

Total potential refers to the entire quantity of parking lot solar possible.

Data and methods

First, we used a crowdsource-generated shapefile obtained from OpenStreetMaps.com to identify a subset of the parking lots throughout Rhode Island. While in many situations, users have developed polygons that accurately represent the dimensions of parking lots across the state, this dataset is far from comprehensive. Generally, parking lot data tends to be more complete in more populated areas while some cities and towns lack any parking lot data whatsoever.

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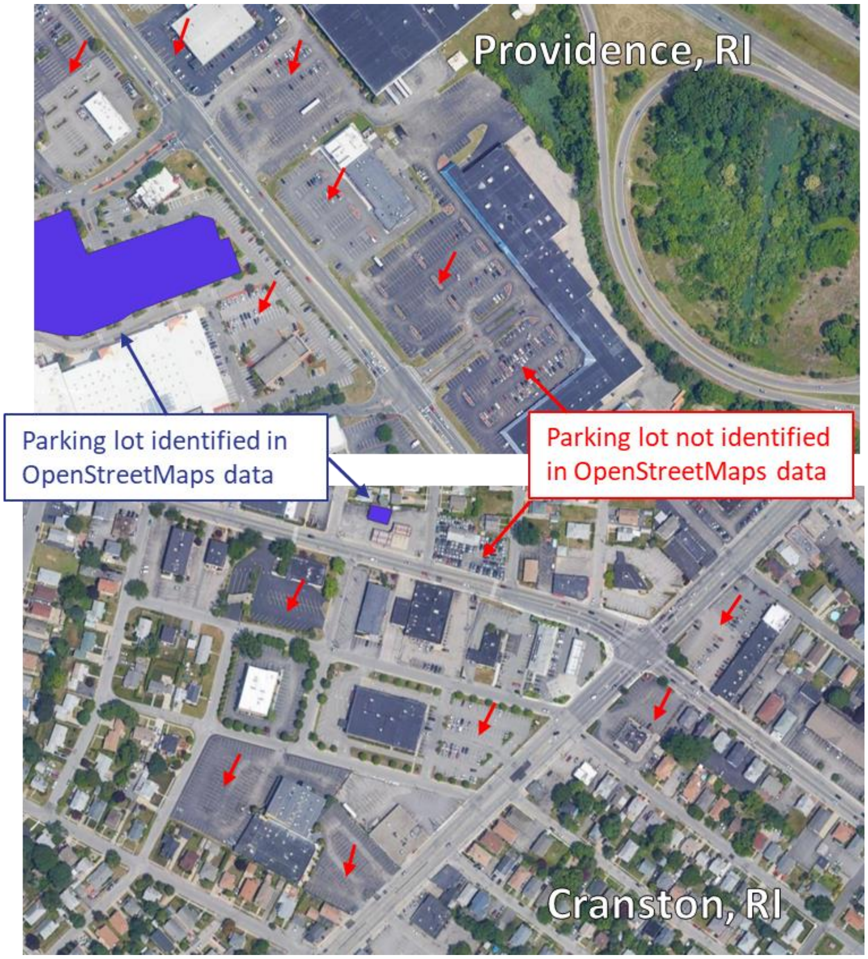
[38] Data downloaded from http://download.geofabrik.de/north-america/us/rhode-island.html, accessed October 2019.

[39] U.S. Census data obtained from RI GIS clearinghouse at http://www.rigis.org/datasets/us-census-2000-summary-file-3-population-and-statewide-housing.

As a result, we performed a series of spot checks for different-sized municipalities (by population) to estimate the number of parking lots not included in the OpenStreetMaps.com dataset. For eight locations across Rhode Island, we analyzed small, medium, and large municipalities and estimated the number of parking lots not mapped in the OpenStreetMaps.com dataset. Figure 27 demonstrates how parking lots were identified as included in the dataset or missing for two example locations. Table 19 describes the results of this calibration step. Each city and town was then classified as small, medium, or large using population data from the U.S. Census and the number of parking lots within that municipality was then scaled up according to the factors described in Table 19.[40] The resulting parking lot areas were then multiplied by the same NREL-derived factor describing the quantity of ground-mounted solar able to be installed per square kilometer used in the ground-mounted solar analysis. This capacity factor was based on discussions with solar developers, who indicated that siting parking lot solar for maximum solar output was more akin to ground-mounted solar than rooftop-mounted solar.

Figure 27. Example of parking lot calibration step using OpenStreetMaps.com dataset



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[40] For municipalities that did not have any parking lots mapped in the OpenStreetMaps.com dataset, we applied a number derived from the statewide average.

Table 19. Estimate of parking lots missing from OpenStreetMaps.com dataset by municipality population

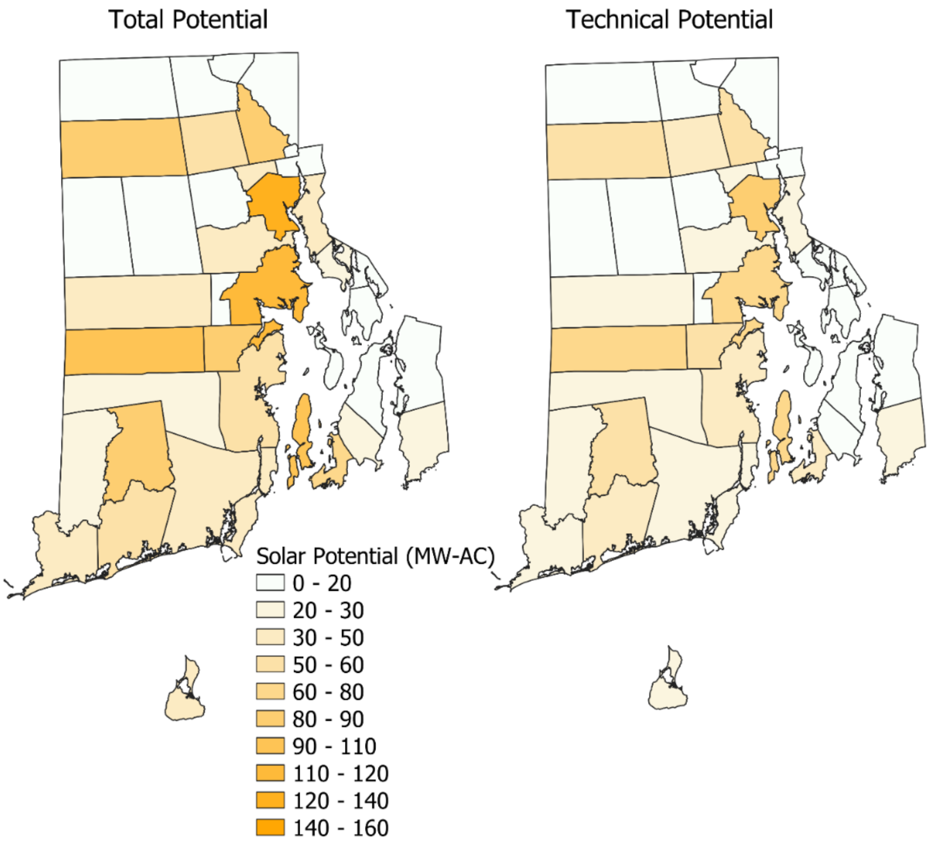
City size	Definition by population	% of parking lots estimated missing from OpenStreetMaps.com dataset
Small	<10,000	97.5%
Medium	10,000 to 100,000	85%
Large	>100,000	60%

Findings

We calculate the total potential of parking lot solar at approximately 1,590 MW. Providence has the highest total potential, at 130 MW.

Given the limitations of the geospatial parking lot data (crowd-sourced and focused on only certain parts of the state), these potential estimates likely have a high level of uncertainty. Furthermore, because there is limited literature available on land use dedicated to parking lots in Rhode Island, validation of the OpenStreetMaps data and the resulting estimates of parking lot solar potential is challenging.

Figure 28. Maps of total and technical parking lot solar potential (MW)



Technical potential

Technical potential is a subset of total potential that includes only areas that are suitable for solar development.

Data and methods

To estimate technical potential, we applied a building setback to the GIS data obtained from OpenStreetMaps.com. Using the building footprint shapefile from RI GIS (described above in Chapter 2. Rooftops), we removed any areas that were within 50 feet of a building in order to avoid impacts of shading (see "Estimating setbacks" sidebar in Section 3.1).[41] As with total potential, these technical potentials were then adjusted to reflect the number and area of parking lots likely to be missing from the OpenStreetMaps.com dataset. Our analysis does not take into account any reductions reflecting owners' possible preferences for avoiding siting solar along main road frontage in order to maintain business visibility.

Findings

The statewide technical potential is calculated to be 1,060 MW, with the highest potential located in Providence (80 MW).

4.2. Estimated annual generation

The estimated annual generation (measured in GWh) for total and technical potential on carport solar sites was calculated using an NREL-derived capacity factor of 20 percent for solar facilities in Rhode Island.[42] The technical potential for parking lot solar totals 1,820 GWh. As a point of reference, according to ISO New England, wholesale electricity load for Rhode Island in 2020 totaled 7,826 GWh.[43] Although this technical potential represents 23 percent of the current electricity load for Rhode Island, the ability for solar to completely meet in-state electricity demand is limited by timing of generation and demand, hosting availability (see Chapter 5), and other factors.

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[41] A single setback number was used for purposes of simplicity. Each of the 39 towns and cities in Rhode Island has its own zoning ordinance, which may contain different rules governing setbacks on different parcel types (dense commercial, low-rise industrial, downtown area, etc.). The actual required setback at each parking lot may differ based on these zoning ordinances, as well as physical features at the site (e.g., height of nearby buildings or trees).

[42] Brown, A., P. Beiter, D. Heimiller, C. Davidson, P. Denholm, J. Melius, A. Lopez, D. Hettinger, D. Mulcahy, and G. Porro. 2016. "Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results." National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy15osti/64503.pdf.

[43] ISO New England's 2020 CELT Forecast, available at https://www.iso-ne.com/static-assets/documents/2020/04/forecast_data_2020.xlsx. Note that this number refers to net demand, after taking into account the impact of existing energy efficiency and distributed PV resources.

Table 20. Estimated annual carport-mounted generation (GWh)

	Total potential	Technical potential
Carports	2,730	1,820

Costs

Based on limited data from two existing parking lot solar facilities installed under the REF program through Fall 2019, we estimate that solar installed on carports costs \$5.09/W_{DC} (see Table 21).[44] This is about \$2/W_{DC} higher than the estimated cost of ground-mounted solar or solar installed on non-residential rooftops, and about \$1/W_{DC} higher than the estimated cost of solar installed on non-residential rooftops. This in line with estimates described by two different solar developers (described via survey and phone conversations), who estimate a cost adder of \$1.00 to 1.50 per W_{DC}, relative to rooftop solar. According to discussions with solar developers, these incremental costs are often due to more complexities relating to engineering and permitting, as well as additional costs related to building the carport structure itself. All costs are presented in 2018 dollars.

Table 21. Costs of carport-mounted solar

Cost type	Middle estimate
\$/W_{DC}	\$5.09
\$/MWh_{AC}	\$222

As with other solar categories, the calculation of a \$/MWh_{AC} cost for parking lot solar requires assumptions about capacity factors, DC-to-AC conversion ratios, operating and maintenance costs, and financing costs which may vary in reality for each solar installation.[45]

Avoided emissions

To calculate the avoided emissions associated with each category of solar PV, we used U.S. EPA's AVERT model. We utilized distributed solar PV CO_2 emissions factors from AVERT's Northeast region to calculate the avoided emissions associated with rooftop solar PV in Rhode Island. In total, we estimate

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[44] Parking lot solar installations in Rhode Island remain limited. At the time this report was published, there were known to be fewer than six such installations.

[45] For parking lot solar, we relied the same assumptions as ground-mounted solar: we assume a 20 percent capacity factor (based on data from Brown, A., P. Beiter, D. Heimiller, C. Davidson, P. Denholm, J. Melius, A. Lopez, D. Hettinger, D. Mulcahy, and G. Porro. 2016. "Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results." National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy15osti/64503.pdf), an 87 percent DC-to-AC conversion rate, based on data provided to Synapse by National Grid, a fixed operating and maintenance cost of \$20/kW (based on data from NREL's 2019 "Alternative Technology Baseline" study), a variable operating and maintenance cost of \$0/kWh (based on data from NREL's 2019 "Alternative Technology Baseline" study), and a financing cost of 5 percent (based on data from NREL's 2019 "Alternative Technology Baseline" study).

that the 1,060 MW carport technical potential is capable of avoiding about 1,191,400 metric tons of CO_2, or 1.2 million metric tons ($MMTCO_2$) (see Table 22).

Table 22. Avoided emissions, carport technical potential (metric tons CO_2)

	Avoided GHG emissions
Carports	1,191,400

Caveats and data limitations

We relied on crowdsourced geospatial data from OpenStreetMaps.com, a tool for creating and sharing map information, to estimate the number and area of parking lots in Rhode Island. Although this dataset does provide accurate polygons for many parking lots throughout the state, it is largely incomplete. While data created in this dataset relies on local knowledge, anyone can contribute to it and the ultimately quality of the data depends on the input of the contributors. Based on spot checks, parking lot polygons appear to be accurate at a high level, but data quality is typically better in urban areas (especially downtown Providence) as opposed to rural areas. In addition, there is limited literature available on land use dedicated to parking lots in Rhode Island which makes validation of OpenStreetMaps data challenging. As a result, our total and technical potential estimates are uncertain.

Existing data on carport solar is currently very limited. For this analysis, we had access to cost data at two installations that existed as of Fall 2019. By Summer 2020, there were roughly half-dozen installations in Rhode Island. Because of the limited number of in-state installations, assumptions on capacity factor and kilowatts-per-square-kilometer were instead based on conventional ground-mounted solar installations solar data. Actual values for parking lot solar installations may be different.

Our analysis does not take into account that buildings adjacent to parking lots may be taller or shorter than assumed here. This could impact the necessary setback and affect the overall technical potential. Likewise, our analysis does not take into account any setback requirements due to zoning or owners' preferences (e.g., avoiding siting solar along main road frontage in order to maintain business visibility).

Finally, our analysis also does not include any estimates of solar that could be installed on parking garages or other existing parking structures. Including carport solar sited at these facilities could increase the overall technical potential estimated here.

5. SOLAR POTENTIAL FROM ALL CATEGORIES

The preceding sections of the report analyze the total, technical, and economic potentials of solar within each category independently. However, some constraints that potentially impact the overall buildout of solar in Rhode Island may restrict the quantity of solar in aggregate. For example, solar of all categories contribute to a single hosting capacity—the amount of distributed energy resources that can be accommodated on the distribution system without adversely impacting power quality or reliability—for a given area. The following section discuss the aggregate impacts of solar by municipality (supplemented by data in Appendix E) and is followed by a section that discusses the impact of hosting capacity on municipality-wide solar potential.

5.1. Aggregate impacts by municipality

For purposes of comparison, we illustrate how these solar technical potentials compare to each municipality's annual retail sales. Figure 29 compares the average technical potential generation (estimated by averaging the "low" end and "high" end estimates for each municipality's technical potential) with retail electricity sales in each municipality.[46] For purposes of comparison, 20 of 39 municipalities—or roughly half—are estimated to have solar technical potentials that are smaller than that municipality's annual electricity sales. 19 municipalities have potentials that range from roughly equal to the municipality's electricity sales, to some multiple of that municipality's electricity sales.

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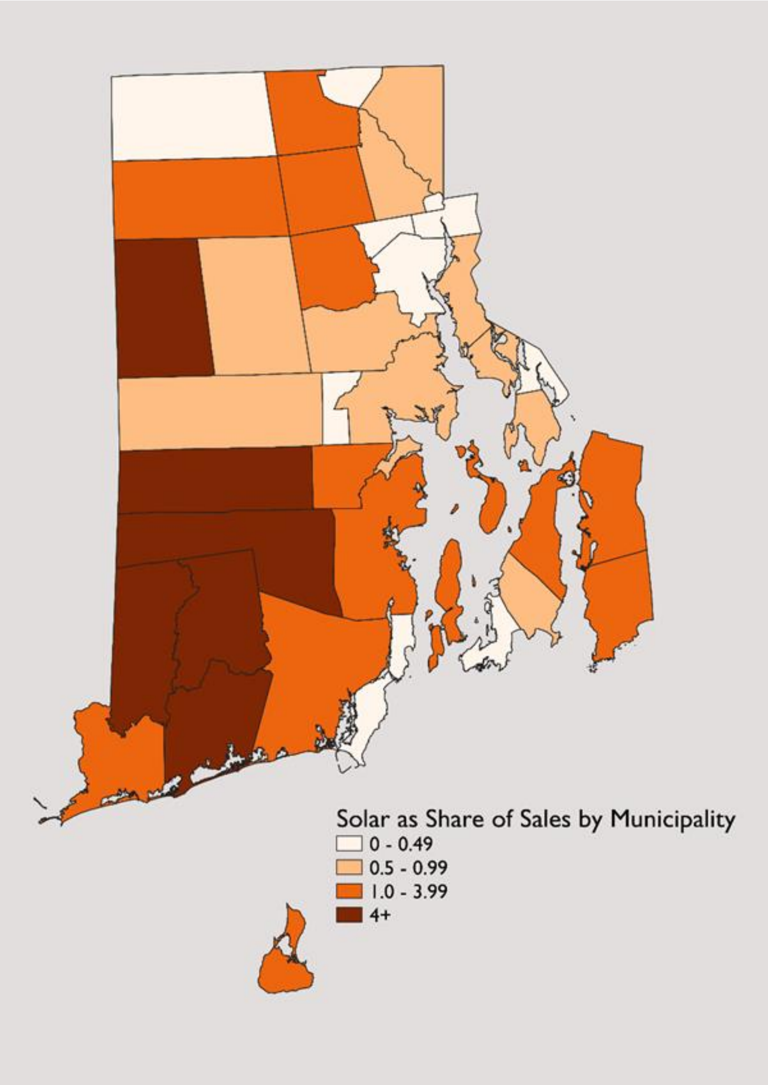
[46] Retail electricity sales are calculated for each municipality using 2018 data from EIA's Form 861 (available at https://www.eia.gov/electricity/data/eia861/), but split out the total by town based on the town-specific sales provided by National Grid. EIA Form 861 reports statewide data for National Grid, Block Island Electric Co, and Pascoag Utility District. We assume that 100 percent of Block Island Electric Co's retail sales are in New Shoreham, and that 100 percent of Pascoag Utility District's retail sales are in Burrillville. We also assume that the retail sales for Pascoag Utility District comprise 50 percent of Burrillville's total electricity sales. We then allocate the remaining National Grid sales to each municipality based on population data obtained from U.S. Census.

Figure 29. Map of aggregate technical potential relative to retail electricity sales



Caveats

This analysis compares annual solar generation to annual retail electricity sales. These values may not be comparable on a daily or hour-by-hour basis, as solar generation does not perfectly match electricity consumption. For example, in summer months, solar output often peaks around noon, whereas the demand for electricity may not peak until later in the evening. Other technologies and practices, such as demand response and energy storage, may be able to better match electricity supply with electricity demand and more easily allow solar to provide a larger share of Rhode Island's electricity.

5.2. Impacts of hosting capacity

Hosting capacity is defined as the amount of distributed energy resources that can be accommodated on the distribution system without adversely impacting power quality or reliability. Unlike many other constraints assessed in this analysis (e.g., setbacks, land-use type) hosting capacities are physical constraints that can be overcome with infrastructure upgrades. In other words, though hosting capacities of a distribution system may be limited now, they can be mitigated through some amount of capital expenditure.

These capital expenditures can—in certain cases—be expensive relative to the size of the project. In other cases, these capital expenditures could potentially be reduced as a result of distributed storage to limit export to the grid, mitigating system upgrade needs and/or costs.

Case Study: Hosting Capacity Upgrade Costs

The cost to upgrade a distribution system in order to expand its hosting capacity may be high. To assist with understanding these costs, Revity Energy, a solar installer in Rhode Island, provided information on several projects that were not ultimately pursued because of hosting capacity costs.

Revity's team members note that in situations that require line upgrades, on average over the last 2 years, they have observed costs of $1.5 million per mile in line upgrades. In one instance, Revity noted that given the distance of the proposed solar installation from the closest substation, Revity estimated the total line upgrade could cost $13.5 million (compared to an estimated upfront cost of a $16 million for a 5 MW installation built at the median price of $3.21 described in Table 15). In addition, Revity has observed that in situations where substation upgrades are required, additional transformer banks may be needed, doubling total interconnection costs.

Note that this case study is included in order to provide context on possible costs associated with expanding hosting capacity. These costs to upgrade the distribution system are not necessarily unique to solar proposed on brownfield, landfill, or gravel pit sites, and may be a consideration at any proposed solar facility. However, the costs cited in this case study may not necessarily be representative of all installations or situations.

Data provided

Synapse received feeder hosting capacity data and shapefiles from National Grid, which contain information on the hosting capacity for 3-Phase lines throughout Rhode Island (Figure 30).[47] National Grid also provided shapefiles for 1- and 2-phase lines, but these lines do not have any numerical data about hosting capacity.

For each 3-phase line, we have several datapoints. These include the amount of distributed generation (DG) capacity currently connected to the line and the amount of DG capacity that is pending. The 3-phase lines are often very large and frequently span across municipalities. In many situations, the lines have forks or loops, which means that they are difficult, and usually impossible, to assign to a single municipality.

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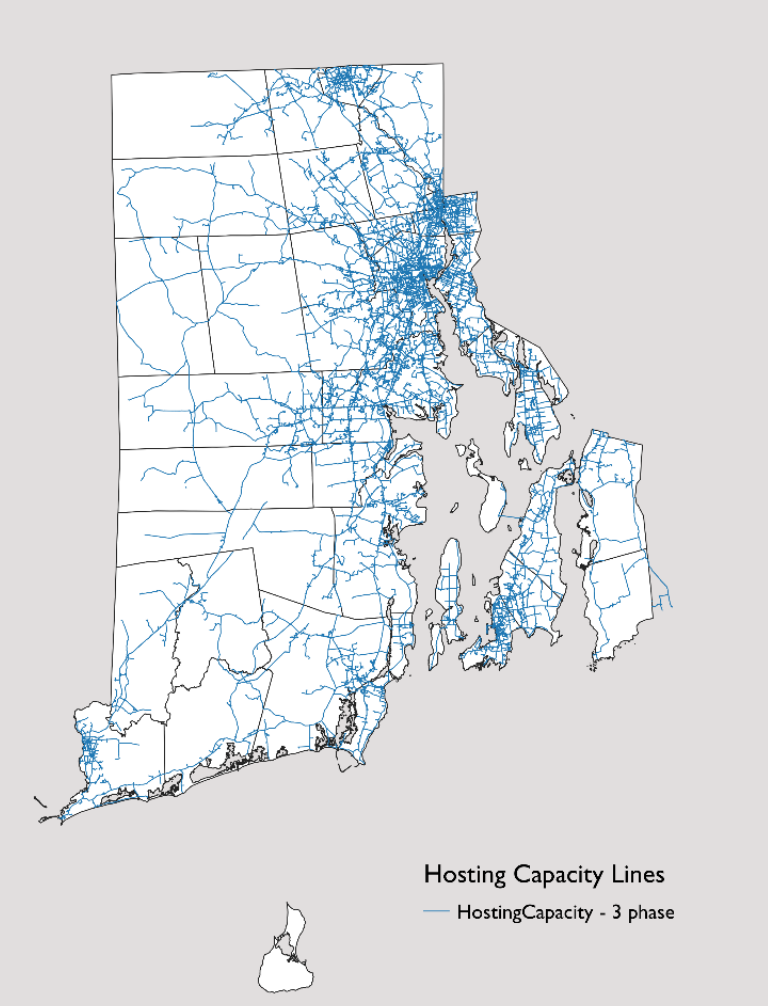
[47] A non-downloadable version of this data is also available at: https://www.arcgis.com/apps/MapSeries/index.html?appid=36c3c4ba3f92493a8d81aea4fae22d9d. Data used in this analysis was last updated November 12, 2019.

This 3-phase data also includes two types of information about available hosting capacity:

- The data points identified by National Grid as “Min Hosting Capacity” state that for any single 3-phase line, there is a segment of it that is limited in hosting capacity. For example, if this listed number were 150 kW, it might mean that for a 10-mile line, there could be a segment ¼ mile long that has a maximum hosting capacity of 150 kW. These numbers do not take into account any installed or pending DG capacity (i.e., if this limiting segment had 150 kW of DG currently installed, this number will still read as 150 kW).
- Meanwhile, the data points identified as “Max Hosting Capacity” also apply to only a single segment of the 3-phase line. But these refer to the maximum available capacity that is available for some segment of that line. For our 10-mile line example, this might mean that there is a 1-mile segment where there is 800 kW of capacity available. Unlike “Min Hosting Capacity,” this second capacity number is reported *in addition* to existing DG.

Figure 30. 3-phase feeder lines in Rhode Island



The data received from National Grid represents the hosting capacity at a certain point in time (e.g., as of November 12, 2019). This hosting capacity evolves as the distribution grid changes. Because we cannot discern what the hosting capacities are at the sub-line resolution, and because we cannot assign lines to specific municipalities, it is impossible to identify the actual hosting capacity with any certainty. Given this limitation, we have performed a series of analyses that help to compare certain hosting capacity datapoints to aggregate technical capacity.

Approach

We divided our hosting capacity approach into two analyses: a project perspective analysis and a policy perspective analysis. The project perspective considers the hosting capacity issue from the perspective of a single installation: Where can a solar PV installation currently be hosted given capacity constraints? The policy perspective considers the hosting capacity issue from the perspective of multiple solar installations: What is the gap between solar PV potential and hosting capacity across the state, and where are the biggest gaps?

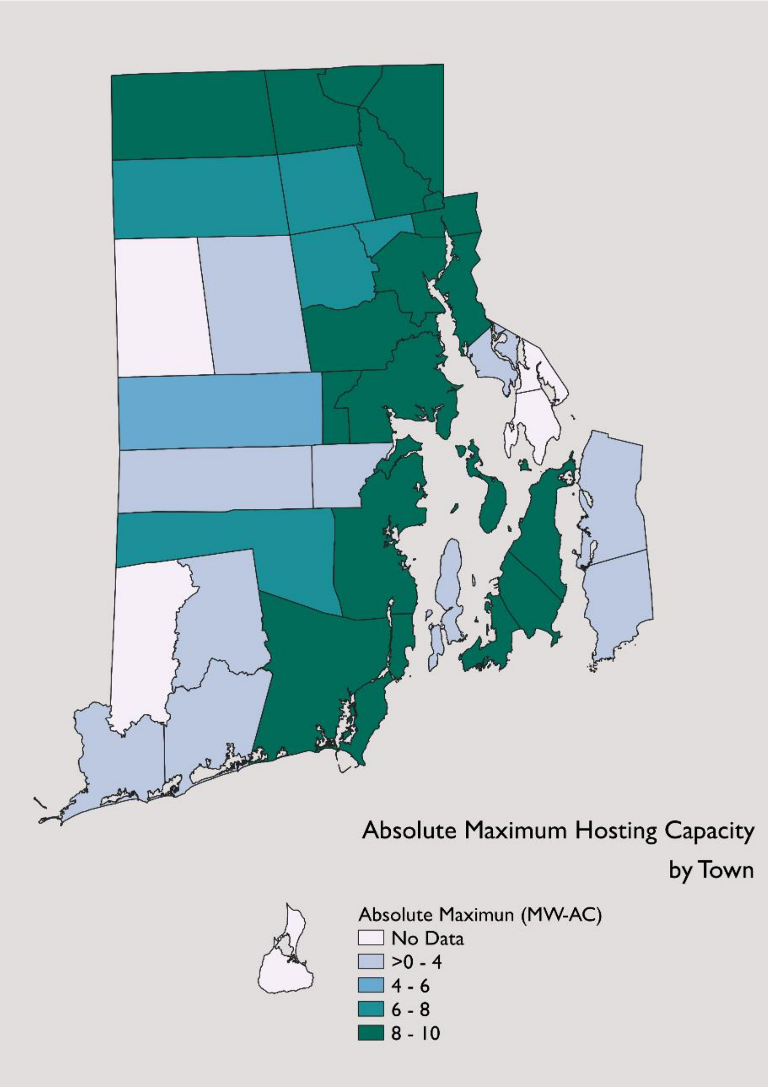
Project Perspective

For the project perspective analysis, we first identified all 3-phase feeder lines that go through each of the 39 municipalities. For each municipality, we examined the maximum incremental hosting capacity for any one of the lines that crosses the municipality boundaries. Figure 31 identifies the maximum hosting capacity currently allowable for each municipality on any one line.

Because lines cross municipal boundaries, and because we do not have data on where the maximum capacity is located on the line, it is possible that some of the observed maximum quantities are appropriate for certain municipalities, but not others.

According to this figure, 21 municipalities have a maximum available hosting capacity of 8 to 10 MW on at least one line. 15 towns have a maximum available hosting capacity of 0-8 MW on at least one line. Three municipalities do not have any 3-phase feeder lines or have missing data for the lines that do cross town boundaries. Municipalities in eastern parts of the state tend to have higher maximum incremental hosting capacities than municipalities in western parts of the state. This may be because these towns are more densely populated and therefore have a larger electric grid infrastructure.

Figure 31. Maximum incremental hosting capacity by municipality (project perspective)



Policy Perspective

For the policy perspective, we compared the range of aggregate technical capacities (rooftops, landfills, gravel pits, C&I parcels, parking lots, and brownfields) with the range of hosting capacities (see Figure 32). The "low" end of each hosting capacity is calculated by summing the minimum hosting capacities for each of the lines within each municipality.[48] The "high" end of each hosting capacity is calculated by summing the maximum hosting capacities for each of the lines within each municipality. Because lines cross municipal boundaries, and because we do not have data on where the specific maximums or minimums are located, it is possible that some of the stated quantities are appropriate for certain municipalities, but not others. Using this approach, we find that the towns of Exeter, Foster, and West

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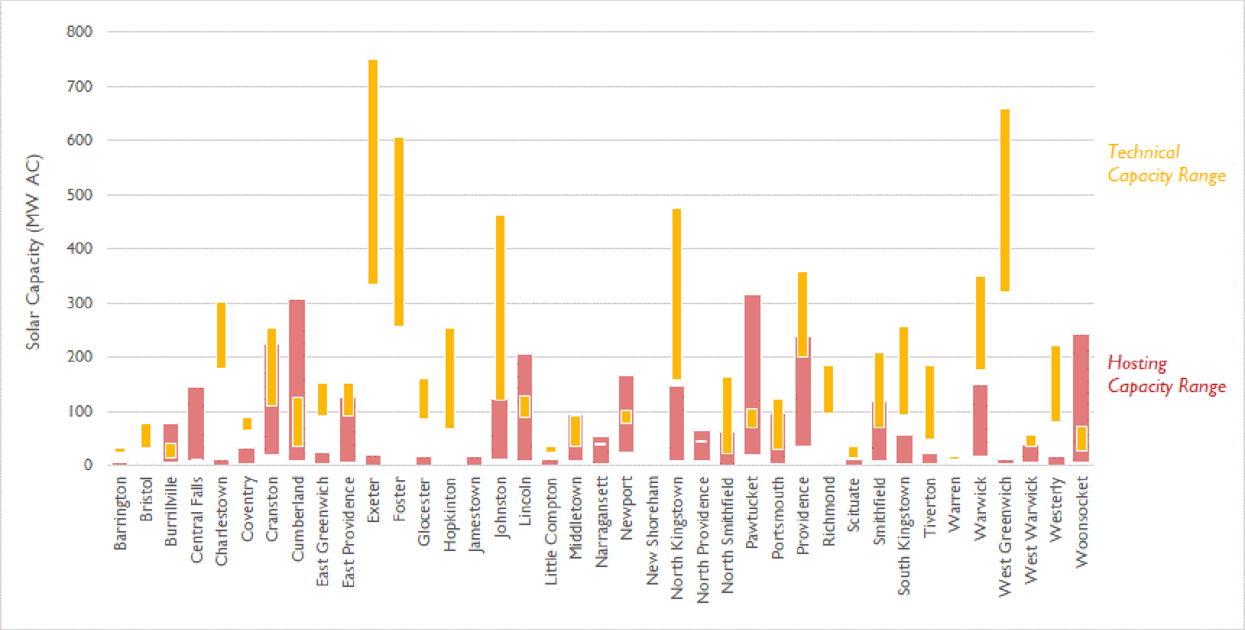
[48] The actual minimum hosting capacity at certain points of the line may in fact be smaller, as the reported minimum hosting capacity does not account for any existing distributed resources.

Greenwich have the largest hosting capacity "gaps" in the state—each in excess of 430 MW. These towns have very high solar technical capacities and therefore may be priority towns for distribution system upgrades in the near future.

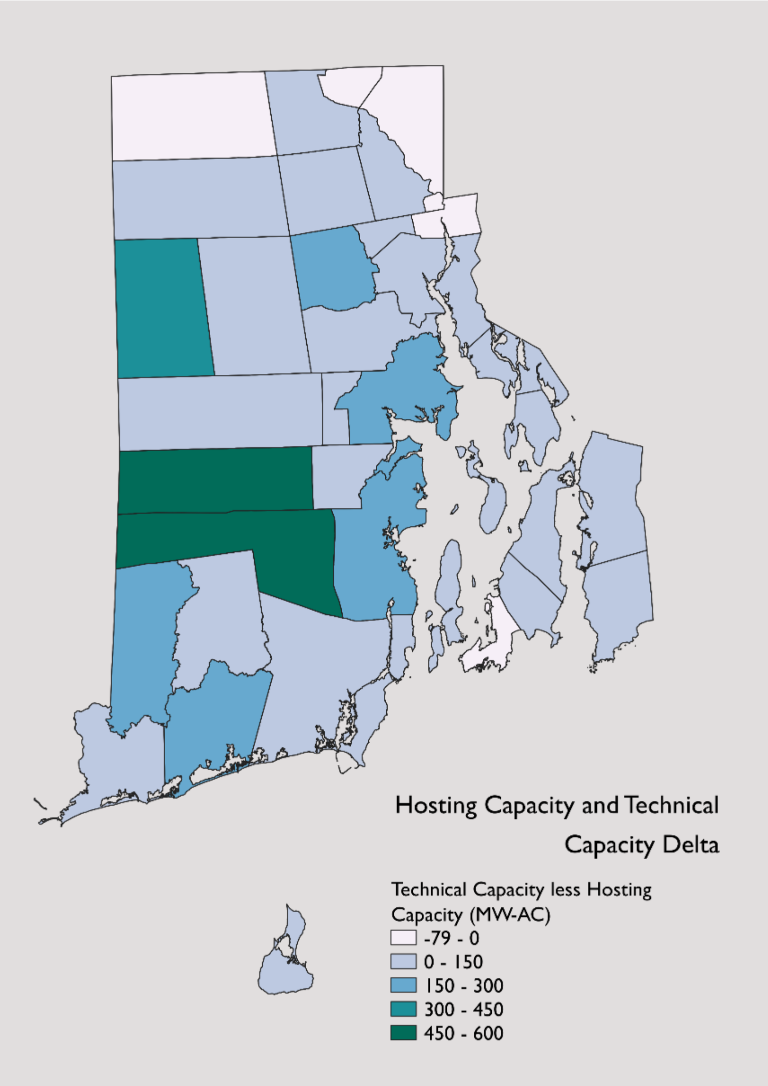
Figure 32. Technical solar capacity and hosting capacity ranges for each municipality in Rhode Island



This concept can be illustrated another way in map format. Subtracting the average hosting capacity from the average technical capacity in each municipality demonstrates the approximate hosting capacity "gap" for each municipality (see Figure 33). Looking at the entire state, about 85 percent of municipalities have a hosting capacity gap, meaning that 85 percent of municipalities have technical potentials that exceed their hosting capacities.

In summary, there is justification for a more thorough hosting capacity analysis for the state of Rhode Island using more granular geospatial data, if available. Such a study would provide more precise insights into which towns, and which distribution feeders, could benefit most from hosting capacity upgrades to support the adoption of solar.

Figure 33. Hosting capacity gap for each municipality in Rhode Island (policy perspective)



Note: Positive numbers indicate municipalities where the estimated technical potential exceeds the estimated hosting capacity. In contrast, negative numbers indicate municipalities that have larger hosting capacities than technical potentials.

6. CONCLUSION

Synapse's granular bottom-up geospatial analysis of Rhode Island's solar potential demonstrates that the state is host to between 3.4 and 7.3 GW of solar technical potential, with commercial and industrial developed and undeveloped parcels representing the largest category—up to 4.6 GW (Table 25). Parking lots represent the second-largest category, though the state has seen only very limited parking lot solar installations (e.g., fewer than ten) to date.

Within the residential category, single family rooftops have a higher economic potential than multifamily rooftops, with a potential up to 220 MW (Table 24), concentrated in the eastern portion of the state.

Table 23. Summary of potentials and costs, rooftops

Subcategory	Technical potential (MW)	Technical potential (GWh)	Estimated cost ($/Watt-DC)	Estimated cost ($/MWh-AC)	Potential avoided GHG emissions (MMTCO2)
Rooftop	850	1,130	$3.07 – $4.15	$153 – $208	0.74
Landfills	70 – 260	120 – 450	$3.21	$122	0.07 – 0.27
Brownfields	260 – 650	450 – 1,120	$3.21	$122	0.27 – 0.69
Gravel pits	30 – 90	50 – 160	$3.21	$122	0.03 – 0.10
Commercial and industrial parcels	1,160 – 4,600	1,990 – 7,920	$3.21	$122	1.21 – 4.83
Parking lots	1,060	1,820	$5.09	$188	1.19
Total	**3,390 – 7,340**	**5,560 – 12,600**	**-**	**-**	**3.47 – 7.65**

Table 24. Summary of total, technical, and economic potentials for residential rooftop solar

Subcategory	Total potential (MW)	Technical potential (MW)	High Economic Potential (MW)	Low Economic Potential (MW)
Residential Single Family	2,100	440	220	90
Residential Multifamily	480	100	40	20
Total	**2,580**	**540**	**260**	**110**

Though Rhode Island is host up to 4,680 MW of solar potential on rooftops, brownfields, landfills, gravel pits, and parking lots, the cost of developing these sites may be higher than equivalent installations on conventional ground-mounted sites due to additional permitting, construction, and site remediation costs. These incremental costs are likely to be site-specific and vary across sites with different characteristics. Though siting solar on these types of sites may address siting or environmental concerns, there are potential tradeoffs given potentials for additional costs and lower-than-average annual generation. Furthermore, hosting capacity limitations may also pose a tradeoff when deciding where to site solar projects. Our analysis indicates there are many towns across the state where distribution hosting capacity upgrades may be advantageous for interconnecting the state's future solar potential.

APPENDIX A. EXISTING SOLAR

Table 25. Existing solar installations and capacity by program and installation type

Program	Subprogram	Type	Total Installations	Total MW_{AC}	Range MW_{AC}
REF	Brownfield Solar PV Program	Roof	-	-	-
REF	Brownfield Solar PV Program	Ground	-	-	-
REF	Commercial Scale Program	Roof	108	14	0.009 - 5.692
REF	Commercial Scale Program	Ground	18	21	0.009 - 4.630
REF	Commercial Scale Program	Carport	2	0.4	0.048 - 0.174
REF	Commercial Scale Program	Unknown	1	0.2	0.217 - 0.217
REF	Commercial Scale Program	Roof/Ground Combination	2	0.4	-
REF	Commercial Scale Program	Roof/Ground/Carport Combination	-	-	0.118 - 0.169
REF	Small Scale Program	Roof	1,123	8	0.000 - 0.000
REF	Small Scale Program	Ground	60	0.5	0.001 - 0.022
REF	Small Scale Program	Roof/Ground Combination	1	0.01	0.001 - 0.024
REG, Small Scale	Commercial	-	13	0.1	0.006 - 0.015
REG, Small Scale	Individual	-	3,375	20	0.002 - 0.016
REG, Small Scale	Third-party owned	-	98	0.5	0.002 - 0.022
REG, Large Scale	Commercial-Scale Solar	Ground	9	7.1	0.434 - 0.868
REG, Large Scale	Commercial-Scale Solar	Rooftop	2	1.7	0.868 - 0.868
REG, Large Scale	Large-Scale Solar	Ground	4	9.3	1.364 - 3.520
REG, Large Scale	Medium-Scale Solar	Unknown	27	5.5	0.036 - 0.217
REG, Large Scale	Medium-Scale Solar	Rooftop	9	0.9	0.036 - 0.216
REG, Large Scale	Medium-Scale Solar	Ground	1	0.2	0.217 - 0.217
VNM	Unknown	-	20	52	0.060 - 7.387
DG Contracts		-	27	18	0.039 - 2.607
Community Solar Virtual Net Metering Pilot Program		-	1	2.5	2.5
Total			**7,711**	**186**	**-**
All Net Metering	Residential	-	7,341	44	-
All Net Metering	Commercial	-	208	21	-

Note: The data above comes from the following programs: REF, REG (Small), REG (Medium, Large, and Commercial), VNM, DG Contracts Program, the 30 MW pilot, and earlier non-programmatic net-metering. Values of "-" are shown for categories that have MW that have had incentives awarded, but are not existing as of Fall 2019. MW ranges highlight the minimum and maximum values reported for each subprogram. This does not include solar installed between fall 2019 and March 2020, which is estimated to total around 53 MW.
Source: RI Commerce Corporation and National Grid.

APPENDIX B. GEOSPATIAL SOURCES

Table 26. Geospatial data (parcels, addresses, and zoning) provided by municipality

Municipality	Parcels?	Addresses?	Zoning?	Notes
Barrington	Yes	Yes	Yes	
Bristol	Yes	Yes	Yes	
Burrillville	Yes	Yes	Yes	
Central Falls	Yes	Yes	Yes	
Charlestown	Yes	Yes	Yes	
Coventry	Yes	-	Yes	
Cranston	Yes	Yes	Yes	
Cumberland	Yes	-	Yes	
East Greenwich	Yes	-	Yes	
East Providence	Yes	-	-	
Exeter	Yes	-	Yes	
Foster	-	-	-	No digital geospatial data was provided
Glocester	Yes	Yes	Yes	
Hopkinton	Yes	Yes	Yes	
Jamestown	Yes	Yes	Yes	
Johnston	Yes	Yes	Yes	
Lincoln	Yes	Yes	Yes	
Little Compton	-	-	-	No digital geospatial data was provided
Middletown	Yes	Yes	Yes	
Narragansett	Yes	-	Yes	
Newport	Yes	-	Yes	
New Shoreham	Yes	Yes	Yes	
North Kingstown	Yes	-	Yes	
North Providence	Yes	Yes	Yes	
North Smithfield	Yes	Yes	Yes	
Pawtucket	Yes	-	Yes	
Portsmouth	Yes	Yes	Yes	
Providence	Yes	Yes	Yes	
Richmond	Yes	-	Yes	
Scituate	Yes	Yes	Yes	
Smithfield	-	-	-	No digital geospatial data was provided
South Kingstown	Yes	Yes	Yes	
Tiverton	Yes	Yes	Yes	
Warren	Yes	Yes	Yes	
Warwick	Yes	Yes	Yes	
West Greenwich	-	-	-	No digital geospatial data was provided
West Warwick	Yes	-	Yes	Digital geospatial data was provided, but files were corrupted and unusable for this analysis
Westerly	Yes	Yes	Yes	
Woonsocket	Yes	Yes	Yes	

Note: Full geospatial analysis was possible for municipalities that provided both parcel and zoning data. For municipalities that did not provide zoning data, we assumed that similar zoning from municipalities defined as "similar" based on U.S Census data on population, median income, and housing density. Address data was used to identify parcels as brownfields.

Table 27. Other geospatial sources

Data	Description	Source	Link
Building Footprints	Building area shapefile	RIGIS	http://www.rigis.org/datasets/building-footprints?geometry=-71.615%2C41.673%2C-71.533%2C41.685
Median Income	GIS data from the 2010 US Census for RI	RIGIS	http://www.rigis.org/datasets/us-census-2000-summary-file-3-population-and-statewide-housing
Local Permitting	Data on zoning district, including historical districts	Municipalities	See Table 26
Landfills	GIS shapefile from landfill solar potential study	URI	Data provided by Chris Damon, University of Rhode Island Environmental Data Center
Gravel Pits	GIS shapefile for mine plants and operations	USGS	https://mrdata.usgs.gov/catalog/cite-view.php?cite=17
Brownfields	List of brownfields in Rhode Island provided by DEM via OER	DEM	RI DEM. (2019, September 16). *Remediated Sites – Potential Solar*. Available at http://www.dem.ri.gov/programs/wastemanagement/inventories.php.
Land Use	GIS shapefile including the land cover/land use for the State of RI	RIGIS	http://www.rigis.org/datasets/land-use-and-land-cover-2011
Carports	GIS shapefile for publicly sourced parking lot data accessed October 2019	OpenStreetMaps	http://download.geofabrik.de/north-america/us/rhode-island.html
Land Slope	2011 RI LIDAR data	RIGIS	http://www.rigis.org/pages/2011-statewide-lidar
Feeder line Hosting Capacity	Maps of distribution system hosting capacity	National Grid	https://ngrid.apps.esri.com/NGSysDataPortal/RI/index.html

APPENDIX C. CURRENT SOLAR POLICIES IN RHODE ISLAND

Over the years, Rhode Island has supported distributed solar through a number of different mechanisms. Table 28 summarizes these mechanisms, which are detailed in the following paragraphs. As elsewhere, all capacity values in this section are quoted in MW_{AC}.

Table 28. Summary of Rhode Island's distributed solar incentive programs

Program	History	Incentive	Eligibility	Size of the program (MW_{AC})	Administration and subcategorization
Net Metering	Current law passed in 2011; cap of 3% of utility's peak load removed in 2014; currently no cap.	Generation exported to the grid offsets cost of electricity consumed	Customer-sited generation sized to meet on-site loads and based on historical kWh consumption	68 MW of solar as of Fall 2019	Administered by National Grid
Virtual net metering	Enacted in 2011 with net metering; cap on project size raised from 5 MW to 10 MW in 2016	Generation exported to the grid offsets cost of electricity consumed	Public and non-profit entities (including schools and hospitals); up to 10 MW per site	52 MW of solar as of Fall 2019	Administered by National Grid
Community Solar Virtual Net Metering Pilot Program	Legislation passed in 2016 created the set-aside	Generation exported to the grid offsets cost of electricity consumed	Residential customers and affordable housing units	30 MW pilot (2.54 MW installed as of Fall 2019)	Subset of virtual net metering
Renewable Energy Fund	Regulations establishing the program were adopted in 2014	$0.85/kW for residential; $0.70/kW for commercial for the first 50 kW, drops for later blocks (as of Summer 2020)	Solar PV and solar domestic hot water that is net metered and owned by the electricity customer	7 MW small scale and 36 MW commercial installed as of Fall 2019	Divided into small scale, commercial scale, brownfields, and community solar; managed by RI Commerce
Renewable Energy Growth	Originally authorized by law in 2014; successor to the DG contracts program	Long-term fixed price contract; small-scale systems receive pre-determined payment; large scale projects competitively bid	Generation cannot be net metered; res. systems must be sized ≤ historical consumption levels	20 MW small-scale and 25 MW large-scale installed as of Fall 2019	Small scale (solar) and large scale (solar larger than 25 kW, wind, hydro, and anaerobic digesters)
DG standard contracts	Program was available 2011-2014	15-year contracts with projects selected through a competitive procurement based on price and economic factors	Private landowners, businesses, and municipalities with solar PV, wind, and anaerobic digester facilities	18 MW operational as of Fall 2019 (no additional projects pending)	National Grid required to sign 15-year contracts with DG

C.1 Net metering

Rhode Island requires National Grid to offer a net metering tariff for customers with DG. The current implementing law was passed in 2011, and as of 2014 there is no cap on the total amount of renewable capacity that can participate. When a customer enrolls in net metering, any generation exported to the grid offsets an equivalent amount of electricity consumed from the grid and reduces the customer's electric bill. Excess generation beyond a customer's total consumption within a given billing period is compensated at the utility's avoided cost rate up to an additional 25 percent of a customer's consumption for the billing period. DG must be connected to the grid at the same place as the customer's load to be eligible for net metering, though there are exceptions through virtual net metering and the community solar pilot. As of December 2, 2019, a total of 68 MW of solar was net metered in Rhode Island (not including virtual net metering or community solar).[49]

C.2 Virtual net metering

Virtual net metering is a subset of net metering that applies the same incentive mechanism to DG installations that are not located at the site of a customer's load. It was enacted in 2011 with the current implementation of net metering. The virtual net metering option is available to public and non-profit entities, state agencies, quasi-state agencies, municipalities, public housing authorities, public schools, private schools, non-profits, federal government, and hospitals.[50] In 2016, the maximum project size was raised from 5 MW to 10 MW.[51] As of Fall 2020, 52 MW of DG was virtually net metered.[52]

C.3 Community Solar Virtual Net Metering Pilot Program

The Community Solar Virtual Net Metering Pilot Program allows residential electric customers to take advantage of net metered distributed renewable generation without needing to site the resource at the point of the load. Through the program, residential customers can benefit from participation in a community solar project from which they receive net metering credits. Customers pay the third-party developers for their share of a community solar project's output. In 2016, the state legislature passed a law authorizing 30 MW of community solar. Six projects will provide the full 30 MW, with the latest

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[49] Rhode Island Office of Energy Resources. December 5, 2019. *Rhode Island Distributed Generation Solar Updates*. Available at: https://www.iso-ne.com/static-assets/documents/2019/12/p2_dgfwg_ri2019.pdf.

[50] Rhode Island Office of Energy Resources. Accessed April 27, 2020. "Net Metering and Virtual Net Metering Overview." Available at: http://www.energy.ri.gov/policies-programs/programs-incentives/net-metering.php.

[51] National Renewable Energy Laboratory. Accessed April 27, 2020. "Midmarket Solar Policies in the United States: Rhode Island." Available at: https://www.nrel.gov/solar/rps/ri.html.

[52] Rhode Island Office of Energy Resources. December 5, 2019. *Rhode Island Distributed Generation Solar Updates*. Available at: https://www.iso-ne.com/static-assets/documents/2019/12/p2_dgfwg_ri2019.pdf.

project breaking ground in November 2019.[53] According to National Grid, 26.621 MW of solar have been reserved and another 3.379 MW remain available to potential subscribers as of February 2020.[54]

C.4 Renewable Energy Fund

The REF program, managed by RI Commerce, provides grants for individuals and businesses who install DG and participate in net metering. Regulations establishing the program were adopted in 2014.[55] The program is divided into four separate categories: small scale (including residential), commercial scale, brownfields, and community solar. Small-scale projects can be either solar PV generation or solar domestic hot water and must have high quality access to the sun.[56]

REF rebates are distributed on a per-kW basis. As of Summer 2020, the incentive for residential customers is $0.85/kW (for up to 8.235 kW.)[57] Commercial customers can receive $0.70/kW for the first 50 kW of a project, and declining amounts for subsequent 50-kW blocks (maximum of $75,000/project.)[58] As of Fall 2019, the REF program had awarded 10 MW of small-scale projects, 54 MW of commercial-scale projects, and 11 MW of brownfields projects.[59]

C.5 Renewable Energy Growth

The REG program offers pre-determined per-kWh payments for renewable generation through a buy-all/sell-all contract. For small-scale solar installations to be eligible for the program, systems must be sized at or smaller than historical electricity consumption levels and cannot be net metered. Under the program's buy-all/sell-all structure, DG is metered separately from customer load. The customer is compensated at the fixed incentive level for the duration of the REG contract (either 15 or 20 years.) The REG program was established in 2014 as the successor to the Distributed Generation Standard Contracts program, and unlike the Standard Contracts program, REG incorporates small-scale solar in addition to larger projects. The original goal of the REG program was to incentivize 160 MW of renewable

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[53] ecoRI News. November 14, 2019. "Ground Broken on Largest Community Solar Project." Available at: https://www.ecori.org/renewable-energy/2019/11/14/d4vcl1zd7zmqrjpdcbi75vpceyvnol.

[54] National Grid. March 2, 2020. "RI – Net Metering." Available at: https://ngus.force.com/s/article/Net-Metering-in-Rhode-Island.

[55] Rhode Island Department of State. Accessed April 27, 2020. "2014-2016 Rules and Regulations for the Renewable Energy Development Fund Programs." Available at: https://rules.sos.ri.gov/regulations/part/870-20-00-1/7592.

[56] Rhode Island Commerce. December 30, 2019. *Small-Scale Program Request for Proposals*. Available at: https://commerceri.com/wp-content/uploads/2019/05/Small-Scale-Solar-Requests-for-Projects-12.30.19.pdf.

[57] Rhode Island Commerce. December 30, 2019. *Small-Scale Program Request for Proposals*. Available at: https://commerceri.com/wp-content/uploads/2019/05/Small-Scale-Solar-Requests-for-Projects-12.30.19.pdf.

[58] Rhode Island Commerce. December 30, 2019. *Commercial-Scale Program Request for Proposals*. Available at: https://commerceri.com/wp-content/uploads/2019/05/Commercial-General-Requests-12.30.19.pdf.

[59] Rhode Island Office of Energy Resources. December 5, 2019. *Rhode Island Distributed Generation Solar Updates*. Available at: https://www.iso-ne.com/static-assets/documents/2019/12/p2_dgfwg_ri2019.pdf.

generation between 2015 and 2019.[60] This program has since been extended from 2020 to 2029, with a goal of installing 40 MW per year.[61]

REG has two approaches for incentives. First, the small-scale component incorporates solar projects that are smaller than 25 kW. These projects are paid pre-determined fixed incentive payments. As of April 1, 2020, projects sized 1–10 kW receive $296.50/MWh for 15 years, while projects that are between 11 kW and 25 kW receive $234.50/MWh for a period of 20 years.[62] Second, large-scale projects in the REG program compete for contracts, so the resulting compensation depends on the bids. This category of REG is for solar projects that are larger than 25 kW as well as wind, hydroelectric, and anaerobic digester projects. As of Fall 2019, 43 MW of large-scale projects was operational.[63]

C.6 Distributed Generation Standard Contracts

The Distributed Generation Standard Contracts program existed between 2011 and 2014 to procure distributed solar PV, wind, and anaerobic digester-based generation. The program required National Grid to enter into 15-year contracts, which were awarded based on both price and economic factors. Private landowners, businesses, and municipalities were all eligible to participate in the program. As of Fall 2019, 18 MW of generation awarded contracts through the program was operational with no additional projects pending.[64]

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[60] Rhode Island Office of Energy Resources. Accessed April 27, 2020. "Renewable Energy Growth Program (2014.)" Available at: http://www.energy.ri.gov/policies-programs/ri-energy-laws/renewable-energy-growth-program-2014.php

[61] National Grid. April 3, 2018. "Renewable Energy Growth Program: Expanding Renewable Distributed Generation in Rhode Island." Available at https://www9.nationalgridus.com/non_html/CM6021RenewableDistribution3_18.pdf.

[62] National Grid. April 27, 2020. "Rhode Island Renewable Energy Growth Program." Available at: https://ngus.force.com/s/article/Rhode-Island-Renewable-Energy-Growth-Program.

[63] Rhode Island Office of Energy Resources. December 5, 2019. *Rhode Island Distributed Generation Solar Updates*. Available at: https://www.iso-ne.com/static-assets/documents/2019/12/p2_dgfwg_ri2019.pdf.

[64] Rhode Island Office of Energy Resources. December 5, 2019. *Rhode Island Distributed Generation Solar Updates*. Available at: https://www.iso-ne.com/static-assets/documents/2019/12/p2_dgfwg_ri2019.pdf.

APPENDIX D. POLICES IN OTHER STATES INCENTIVIZING NON-CONVENTIONAL GROUND-MOUNTED SOLAR

In recent years, neighboring states have begun to implement policies that provide incentives for ground-mounted solar that is not located on conventional sites. Neighboring states have also implemented incentives that are available to solar units that are installed on parking canopies. This appendix describes the overall structure of these policies, along with detail on the incentive levels currently provided.

Note that other states throughout New England and the mid-Atlantic region were also examined for this appendix; these states do not appear to currently have policies incentivizing non-conventional ground-mounted solar.[65]

D.1 Massachusetts

The Solar Massachusetts Renewable Target (SMART) program was established to incentivize statewide use and development of solar PV generating units by residential, commercial, governmental, and industrial electricity customers throughout the Commonwealth.[66] It is a tariff-based incentive program intended to offer longer-term incentives to solar generation units. As part of this program, all solar tariff generation units that are larger than 25 kW_{AC} are eligible to receive incentive payments for 20 years and systems below 25 kW_{AC} receive payments for 10 years. The program is a declining block program with the incentive payment decreasing as the capacity block is filled. All units are eligible for a base compensation rate which varies by service territory and size of the system, with smaller systems receiving higher rates.

For example, the base compensation rates for National Grid's Massachusetts territory are $0.31126 per kWh for units that are less than or equal to 25 kW_{AC} and $0.15563 per kWh for units greater than 1 MW (see Table 29).[67] In addition to this base compensation rate, certain units are eligible for an adder known as the compensation rate adder. The compensation adder for solar that is sited on brownfields and eligible landfills are at $0.03 per kWh and $0.04 per kWh, respectively. In addition, any solar generating units that are located on a greenfield are subject to a subtractor between $0.0005 per kWh to $0.0025 per kWh per acre occupied by the solar development depending on the land-use classification and the

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[65] Note that these states—which include Connecticut, New Hampshire, Maine, New Jersey, and Pennsylvania—may have solar installed on non-conventional sites such as landfills, but do not appear to have specific programs incentivizing solar development at these sites.

[66] For more information on the SMART program, see https://www.mass.gov/doc/225-cmr-2000-solar-massachusetts-renewable-target-smart-program/download. Synapse's December 2018 overview of the SMART program, *Getting SMART*, can be found at https://www.synapse-energy.com/sites/default/files/Getting-SMART-16-069.pdf.

[67] Massachusetts SMART Solar Program Base Compensation Rates, http://masmartsolar.com/_/documents/Base-Compensation-Rates.pdf and https://www.mass.gov/doc/capacity-block-base-compensation-rate-and-compensation-rate-adder-guideline-041520.

date on which the land-use classification occurred. The SMART program also established an incentive for canopy solar generation and sites conducive to pollinators.[68] The compensation adder for canopy solar is $0.06 per kWh.

On April 16, 2020, Massachusetts Department of Energy Resources (DOER) issued an emergency rulemaking amending the SMART program.[69] A major part of this emergency rulemaking includes clarifying the land-use categories for which SMART-eligible projects can qualify.[70] These include:

- **Category 1**: This category is itself subdivided into two sub-categories: agricultural and non-agricultural land use. Agricultural land must be land that is currently enrolled in Massachusetts' Chapter 61A tax benefit program. Only certain types of SMART facilities are eligible in this subcategory, including building-mounted and canopy-mounted facilities. All facilities must be sized to be no greater than 200 percent of the annual load of the facility. Facilities that receive the agricultural adder (not necessarily all facilities built on agricultural land) must also meet additional siting criteria.[71]

  Facilities sited on non-agricultural land in this category may be building- or canopy-mounted, sited on brownfields or landfills, or be owned by a public entity. Any facility may be ≤ 500 $kW_{AC.}$ Facilities may be up to 4,999 kW_{AC} if they are sited on land that has been previously developed.

- **Category 2**: This category applies to facilities that are greater than 500 kW_{AC} and less than 5,000 kW_{AC} that are sited on land that has not been previously developed and is zoned for commercial or industrial use. This category also applies to solar of this size that is cited within a zoning overlay district that explicitly allows for this type of solar.

- **Category 3:** This category applies to facilities that are greater than 500 kW_{AC} and less than 5,000 kW_{AC} that do not fall into either Category 1 or Category 2.

Importantly, new ground-mounted facilities are ineligible to receive incentives of any kind under the SMART program if they are sited on permanently protected open space or lands designated as Priority Habitats, Core Habitats, or Critical Natural Lands (provided that these lands do not fall under Category 1). Priority Habitats, Core Habitats, or Critical Natural Lands are all land designations defined by Massachusetts Division of Fisheries and Wildlife BioMap2 framework within the Natural Heritage and Endangered Species Program.[72]

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[68] A canopy solar tariff generation unit is defined as a Solar Tariff Generation Unit with 100 percent of the nameplate capacity of the solar PV modules used for generating power installed on top of a parking surface, pedestrian walkway, or canal in a manner that maintains the function of the area beneath the canopy.

[69] See https://www.mass.gov/info-details/smart-emergency-rulemaking for more information.

[70] See https://www.mass.gov/doc/land-use-and-siting-guideline/download.

[71] This criteria includes not interfering with ongoing use of the land for agricultural purposes. See https://www.mass.gov/doc/225-cmr-2000-smart-clean/download, Section 20.06(1)(d) for more information.

[72] Geospatial data on these designations can be found at http://maps.massgis.state.ma.us/dfg/biomap2.htm.

Table 29. SMART program compensation rates by block, National Grid Massachusetts (nominal $/kWh)

Base compensation rate	
Low income less than or equal to 25 kW AC	$0.35795
Less than or equal to 25 kW AC	$0.31126
Greater than 25 kW AC to 250 kW AC	$0.23345
Greater than 250 kW AC to 500 kW AC	$0.19454
Greater than 500 kW AC to 1,000 kW AC	$0.17119
Greater than 1,000 kW AC to 5,000 kW AC	$0.15563
Location-based adders	
Building mounted	$0.01920
Floating solar	$0.03000
Brownfields	$0.03000
Landfills	$0.04000
Canopy solar	$0.06000
Agricultural	$0.06000
Location-based subtractors	
Greenfield (Category 2)	-$0.00050 per kWh per acre
Greenfield (Category 3)	-$0.00050 per kWh per acre

Notes: All values shown are for the National Grid (non-Nantucket) service territory only. Base compensation rates change with each block. For National Grid Massachusetts' service territory, each block is about 90 MW. For the first 8 blocks, base compensation rates fall by 4 percent per block; after that, they fall by 4 percent per block for standalone systems and 2 percent per block for behind-the-meter systems. Data represents rates and adders as they existed in April 2020. All data obtained from https://www.mass.gov/doc/capacity-block-base-compensation-rate-and-compensation-rate-adder-guideline-041520 and https://www.mass.gov/files/documents/2018/04/26/SMART%20Program%20Overview%20042618.pdf.

D.2 New York

NY-Sun offers financial incentives to install solar panels for residential, non-residential, and large commercial and industrial projects. Incentives are available of a dollar-per-watt basis.[73] Incentives are paid after the photovoltaic system has been connected to the grid. Small commercial projects have the option to receive the incentive payments in two increments based on installation milestones (e.g., a first incentive payment when all system components are delivered to a customer's site and a second incentive payment after a PV system has been connected to the utility grid and inspected by NYSERDA or its representatives).[74] Each of the three regions, Con Edison, Upstate, and Long Island are designated an allocation of megawatts that are eligible for NY-Sun incentives and the incentives remain applicable until the region is fully subscribed. To encourage development on brownfields and landfills, additional $/W incentives are available for ground-mounted solar electric systems. These projects are eligible for an incentive of $0.10 per Watt in addition to the standard nonresidential incentives. For example, for

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[73] See https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Dashboards-and-incentives.

[74] See DSIRE, https://programs.dsireusa.org/system/program/detail/701.

Con Edison, the standard nonresidential incentives range between $0.60 to $1.00 per Watt for the first 50 kW (with additional $0.40 to $0.60 per Watt up to 200 kW total) for certain blocks and $0.15 to $0.60 per Watt up to 7.5 MW for certain blocks.

In addition, incentives may be available for newly constructed solar parking canopies.[75] These incentives are available in addition to standard nonresidential incentives. For example, Con Edison parking canopy incentive adder ranges from $0.20 to $0.30 per Watt depending on the block. This incentive does not appear to be offered by the Upstate and Long Island regions.[76]

D.3 Vermont

In July 2017, the Vermont PUC established rules pertaining to construction and operation of net metering system which set specific incentives for net metering projects on preferred sites.[77] A "preferred site" includes but is not limited to sites certified to be brownfield sites, sanitary landfills, parking lot canopies and the disturbed portion of gravel pits, quarries or similar sites used for extraction of a mineral resources.[78] The incentivized rates are paid on a per kWh basis. The incentives vary based on the size of the installation, and are paid on a net metering basis where the payment rate is equal to the incentives described in Table 30, rather than a retail rate. In 2019, installations on preferred sites received a greater $-per-kWh incentive than similarly sized projects on non-preferred sites ($0.174 per kWh in Category II vs $0.134 in Category IV—an increase of 30 percent). Grants, loans, and in some cases, local tax incentives are available for site assessment, cleanup, and redevelopment or reuse projects on contaminated sites.

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[75] Con Edison defines parking solar canopies as elevated above parking lots or added to an open-top deck of a parking garage structure to provide both shade and energy production. See NY-Sun Con Edison Program Manual, page 10. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Resources-for-Contractors.

[76] See https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Dashboards-and-incentives/ConEd-Dashboard.

[77] See https://puc.vermont.gov/sites/psbnew/files/doc_library/5100-PUC-nm-effective-07-01-2017_0.pdf and http://www.newmoa.org/events/docs/311_272/VT_PreferredSitesJune2018.pdf.

[78] A "sanitary landfill "means a land disposal site employing an engineered method of disposing of solid waste on land in a manner that minimizes environmental hazards by spreading the solid waste in thin layers, compacting the solid waste to the smallest practical volume, and applying and compacting cover material at the end of each operating day.

Table 30. Incentive rates for net-metering projects ($/kWh)

	2017	2018	2019
Category I (up to 15 kW)	$0.189	$0.184	$0.174
Category II (> 15 kW to 150 kW on preferred site)	$0.189	$0.184	$0.174
Category III (> 150 kW to 500 kW on preferred site)	$0.167	$0.154	$0.144
Category IV (> 15 kW to 150 kW on non-preferred site)	$0.149	$0.144	$0.134

Source: Table reproduced from http://www.newmoa.org/events/docs/311_272/VT_PreferredSitesJune2018.pdf, page 5.

D.4 Maryland

The Maryland Energy Administration (MEA) provides grants to install parking lot solar PV canopies with electric vehicle chargers over parking lots. The MEA offers up to $400 per kW (DC) of canopy-mounted solar PV per project with a maximum cap of $200,000 per project.[79] To qualify, the project must consist of at least 7 kW of solar PV panels and consist of at minimum four Level II or Level III charging stations located in the same parking lot. The program is available to businesses, government agencies, and non-profits in Maryland.

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[79] Maryland Energy Administration, Parking Lot Solar PV Canopy with EV Charger Grant Program. https://energy.maryland.gov/Business/Documents/Notice%20of%20Grant%20Availability%20Solar%20Canopy%20FY20.pdf.

APPENDIX E. MUNICIPALITY-SPECIFIC DATA

Data in this appendix is provided at a greater level of precision than in preceding sections in order to illustrate the differences among municipalities

Table 31. Detailed results for each municipality, rooftop solar

Municipality	Number of rooftops	Total potential (MW)	Technical potential (MW)	Low economic potential (MW)	High economic potential (MW)
Barrington	6,700	58.1	12.6	3.4	8.2
Bristol	7,800	72.2	18.1	2.5	6.1
Burrillville	6,400	51.5	10.4	2.0	4.8
Central Falls	3,000	31.3	9.2	0.4	1.0
Charlestown	5,700	42.7	6.6	1.1	2.7
Coventry	14,100	115.5	23.2	4.0	10.2
Cranston	27,100	260.4	68.7	7.8	17.1
Cumberland	11,800	110.6	27.6	3.8	8.4
East Greenwich	5,100	60.7	15.6	3.5	9.3
East Providence	16,500	149.4	41.0	5.8	13.6
Exeter	3,200	27.5	4.8	0.6	1.8
Foster	2,900	21.0	3.2	0.5	1.3
Glocester	4,900	38.7	7.1	1.1	2.6
Hopkinton	4,200	33.2	6.2	0.9	2.3
Jamestown	3,300	27.4	5.3	1.1	2.6
Johnston	11,000	106.4	25.6	2.8	6.2
Lincoln	7,200	87.1	26.5	3.9	9.3
Little Compton	3,300	25.7	3.7	0.6	1.7
Middletown	6,700	71.3	19.1	2.6	5.8
Narragansett	9,200	72.5	16.1	2.8	7.9
Newport	8,300	81.6	21.8	2.1	5.0
New Shoreham	1,900	12.9	3.3	0.6	1.7
North Kingstown	11,200	124.2	37.4	4.4	9.8
North Providence	10,000	95.3	21.8	2.6	6.2
North Smithfield	4,900	49.0	13.0	1.6	4.5
Pawtucket	19,300	172.1	48.5	3.4	7.6
Portsmouth	8,300	76.3	17.1	3.3	8.2
Providence	36,200	355.7	103.1	5.6	12.2
Richmond	3,700	25.9	4.7	1.4	3.2
Scituate	5,000	43.4	7.7	1.3	3.5
Smithfield	7,000	81.5	24.5	4.8	11.0
South Kingstown	13,300	110.4	18.2	3.1	7.4
Tiverton	7,500	62.0	10.1	1.7	3.9
Warren	4,200	38.5	9.9	1.4	3.4
Warwick	32,200	299.7	85.5	10.2	22.8
West Greenwich	2,700	27.0	6.6	1.3	3.7
West Warwick	8,900	77.2	19.5	2.9	6.4
Westerly	11,900	108.0	21.1	2.7	6.4
Woonsocket	10,300	96.6	27.4	1.4	3.2
Total	**366,900**	**3,400.7**	**852.1**	**107.2**	**253.1**

Table 32. Detailed results for each municipality, landfills

Municipality	Number of landfills	Total potential (MW)	Low technical potential (MW)	High technical potential (MW)
Barrington	4	4.5	0.0	2.2
Bristol	2	14.3	3.4	10.2
Burrillville	2	16.4	0.4	7.6
Central Falls	0	0.0	0.0	0.0
Charlestown	2	12.1	2.1	7.5
Coventry	3	17.1	4.0	11.8
Cranston	1	6.5	1.1	3.7
Cumberland	1	5.4	0.2	2.6
East Greenwich	1	2.3	0.0	0.0
East Providence	5	42.9	12.4	32.8
Exeter	0	0.0	0.0	0.0
Foster	1	13.7	3.1	11.7
Glocester	2	13.1	1.2	8.2
Hopkinton	1	13.1	2.7	9.0
Jamestown	1	2.6	0.0	1.7
Johnston	1	2.8	0.0	1.5
Lincoln	3	9.2	0.0	2.3
Little Compton	1	3.4	0.0	2.3
Middletown	0	0.0	0.0	0.0
Narragansett	0	0.0	0.0	0.0
Newport	1	3.0	0.0	2.2
New Shoreham	1	1.3	0.0	0.6
North Kingstown	4	27.3	4.4	17.4
North Providence	0	0.0	0.0	0.0
North Smithfield	3	20.4	2.9	12.2
Pawtucket	1	2.9	0.1	1.6
Portsmouth	1	6.6	0.3	3.1
Providence	1	3.7	0.1	2.3
Richmond	2	55.8	18.7	35.5
Scituate	1	4.6	0.2	2.2
Smithfield	3	16.2	0.1	9.8
South Kingstown	2	34.8	8.4	26.5
Tiverton	3	22.7	2.8	13.5
Warren	3	5.6	0.0	0.9
Warwick	3	19.4	1.9	10.0
West Greenwich	0	0.0	0.0	0.0
West Warwick	1	4.0	0.0	0.4
Westerly	1	10.5	0.4	6.6
Woonsocket	1	6.9	0.0	0.6
Total	**63**	**425.1**	**71.0**	**260.4**

Table 33. Detailed results for each municipality, brownfields

Municipality	Number of brownfields	Total potential (MW)	Low technical potential (MW)	High technical potential (MW)
Barrington	4	1.3	0.0	0.1
Bristol	17	6.9	0.0	0.9
Burrillville	8	1.9	0.0	0.0
Central Falls	11	3.4	0.0	0.5
Charlestown	5	181.6	118.8	168.6
Coventry	16	30.2	11.7	21.8
Cranston	48	38.4	0.0	8.4
Cumberland	25	12.8	5.0	9.3
East Greenwich	7	26.9	10.4	19.4
East Providence	50	40.2	15.6	29.1
Exeter	3	75.4	29.2	54.5
Foster	0	0.0	0.0	0.0
Glocester	2	3.9	1.5	2.8
Hopkinton	4	122.2	13.2	87.3
Jamestown	7	2.6	0.0	0.4
Johnston	22	33.2	0.5	21.9
Lincoln	12	21.7	0.0	7.9
Little Compton	2	0.8	0.3	0.6
Middletown	12	14.6	0.0	3.2
Narragansett	8	1.7	0.6	1.2
Newport	27	22.2	8.6	16.0
New Shoreham	0	0.0	0.0	0.0
North Kingstown	22	67.7	26.2	48.9
North Providence	13	3.0	1.1	2.1
North Smithfield	6	29.6	0.0	9.3
Pawtucket	70	32.2	12.5	23.3
Portsmouth	16	67.2	0.0	29.2
Providence	164	79.8	0.0	22.9
Richmond	3	0.4	0.1	0.3
Scituate	4	1.2	0.0	0.5
Smithfield	19	55.9	0.0	33.0
South Kingstown	15	0.5	0.0	0.0
Tiverton	6	20.0	0.0	8.9
Warren	12	8.9	0.0	2.0
Warwick	35	25.7	0.0	6.0
West Greenwich	1	0.0	0.0	0.0
West Warwick	19	11.0	4.3	8.0
Westerly	11	3.1	0.0	0.2
Woonsocket	32	12.5	0.0	4.5
Total	**738**	**1,060.8**	**259.6**	**653.0**

Table 34. Detailed results for each municipality, gravel pits

Municipality	Number of gravel pits	Total potential (MW)	Low technical potential (MW)	High technical potential (MW)
Barrington	0	0.0	0.0	0.0
Bristol	0	0.0	0.0	0.0
Burrillville	0	0.0	0.0	0.0
Central Falls	0	0.0	0.0	0.0
Charlestown	0	0.0	0.0	0.0
Coventry	1	0.6	0.0	0.1
Cranston	1	59.5	11.2	22.4
Cumberland	2	45.3	2.8	13.1
East Greenwich	0	0.0	0.0	0.0
East Providence	0	0.0	0.0	0.0
Exeter	1	12.6	0.9	4.7
Foster	0	0.0	0.0	0.0
Glocester	0	0.0	0.0	0.0
Hopkinton	0	0.0	0.0	0.0
Jamestown	0	0.0	0.0	0.0
Johnston	0	0.0	0.0	0.0
Lincoln	0	0.0	0.0	0.0
Little Compton	0	0.0	0.0	0.0
Middletown	0	0.0	0.0	0.0
Narragansett	0	0.0	0.0	0.0
Newport	0	0.0	0.0	0.0
New Shoreham	0	0.0	0.0	0.0
North Kingstown	0	0.0	0.0	0.0
North Providence	0	0.0	0.0	0.0
North Smithfield	1	19.7	2.3	7.6
Pawtucket	0	0.0	0.0	0.0
Portsmouth	0	0.0	0.0	0.0
Providence	0	0.0	0.0	0.0
Richmond	1	8.1	0.6	3.4
Scituate	0	0.0	0.0	0.0
Smithfield	0	0.0	0.0	0.0
South Kingstown	2	32.3	2.8	12.1
Tiverton	3	52.5	5.7	20.6
Warren	0	0.0	0.0	0.0
Warwick	0	0.0	0.0	0.0
West Greenwich	0	0.0	0.0	0.0
West Warwick	0	0.0	0.0	0.0
Westerly	1	25.1	1.6	7.8
Woonsocket	0	0.0	0.0	0.0
Total	**13**	**255.6**	**27.9**	**91.7**

Table 35. Detailed results for each municipality, developed and undeveloped commercial and industrial parcels

Municipality	Number of parcels	Total potential (MW)	Low technical potential (MW)	High technical potential (MW)
Barrington	145	41.9	1.4	8.4
Bristol	533	87.5	4.6	41.3
Burrillville	102	42.2	0.7	22.1
Central Falls	274	13.7	0.0	1.2
Charlestown	152	157.0	12.4	79.7
Coventry	326	53.4	0.0	7.9
Cranston	2,240	373.1	1.1	122.5
Cumberland	833	185.0	0.4	73.4
East Greenwich	318	119.5	10.2	63.2
East Providence	583	123.2	0.0	26.8
Exeter	224	909.5	279.8	664.9
Foster	198	803.7	247.7	587.7
Glocester	107	143.7	18.1	84.1
Hopkinton	155	226.7	26.6	132.0
Jamestown	61	4.5	0.0	0.6
Johnston	2,013	780.5	84.4	403.5
Lincoln	265	92.0	0.0	31.1
Little Compton	38	16.6	0.6	9.1
Middletown	487	156.7	7.0	57.3
Narragansett	128	11.1	0.0	1.5
Newport	337	75.0	3.3	19.2
New Shoreham	102	4.6	0.0	0.2
North Kingstown	753	594.7	53.7	332.1
North Providence	703	32.9	0.0	1.3
North Smithfield	565	293.9	1.8	118.7
Pawtucket	981	89.9	0.4	20.6
Portsmouth	430	201.0	10.2	69.2
Providence	6,826	553.2	14.6	145.2
Richmond	130	122.3	9.9	79.5
Scituate	144	45.0	0.0	18.7
Smithfield	272	184.1	6.3	100.4
South Kingstown	523	359.5	36.4	171.7
Tiverton	258	212.6	29.0	131.1
Warren	428	18.4	0.0	2.1
Warwick	2,587	540.3	15.7	174.4
West Greenwich	196	795.3	244.4	581.3
West Warwick	341	75.9	3.2	19.4
Westerly	559	341.6	31.6	159.4
Woonsocket	692	155.1	0.1	41.3
Total	**26,008**	**9,036.9**	**1,155.5**	**4,603.7**

Table 36. Detailed results for each municipality, parking lot parcels

Municipality	Estimated number of parking lots	Total potential (MW)	Technical potential (MW)
Barrington	120	17.5	11.7
Bristol	87	12.7	8.4
Burrillville	27	3.9	2.6
Central Falls	13	1.8	1.2
Charlestown	400	58.5	39.0
Coventry	267	39.0	26.0
Cranston	307	44.8	29.9
Cumberland	20	2.9	1.9
East Greenwich	567	82.8	55.2
East Providence	253	36.8	24.5
Exeter	200	29.2	19.5
Foster	40	5.8	3.9
Glocester	600	87.7	58.4
Hopkinton	200	29.2	19.5
Jamestown	720	105.2	70.1
Johnston	107	15.6	10.4
Lincoln	640	93.5	62.3
Little Compton	216	31.5	21.0
Middletown	120	17.5	11.7
Narragansett	227	33.1	22.1
Newport	453	66.2	44.1
New Shoreham	280	40.9	27.3
North Kingstown	393	57.5	38.3
North Providence	227	33.1	22.1
North Smithfield	40	5.8	3.9
Pawtucket	107	15.6	10.4
Portsmouth	47	6.8	4.5
Providence	870	127.1	84.7
Richmond	640	93.5	62.3
Scituate	67	9.7	6.5
Smithfield	420	61.4	40.9
South Kingstown	287	41.9	27.9
Tiverton	20	2.9	1.9
Warren	20	2.9	1.9
Warwick	760	110.8	73.8
West Greenwich	720	105.2	70.1
West Warwick	107	15.6	10.4
Westerly	273	39.9	26.6
Woonsocket	13	1.9	1.3
Total	**10,872**	**1,588.3**	**1,058.3**

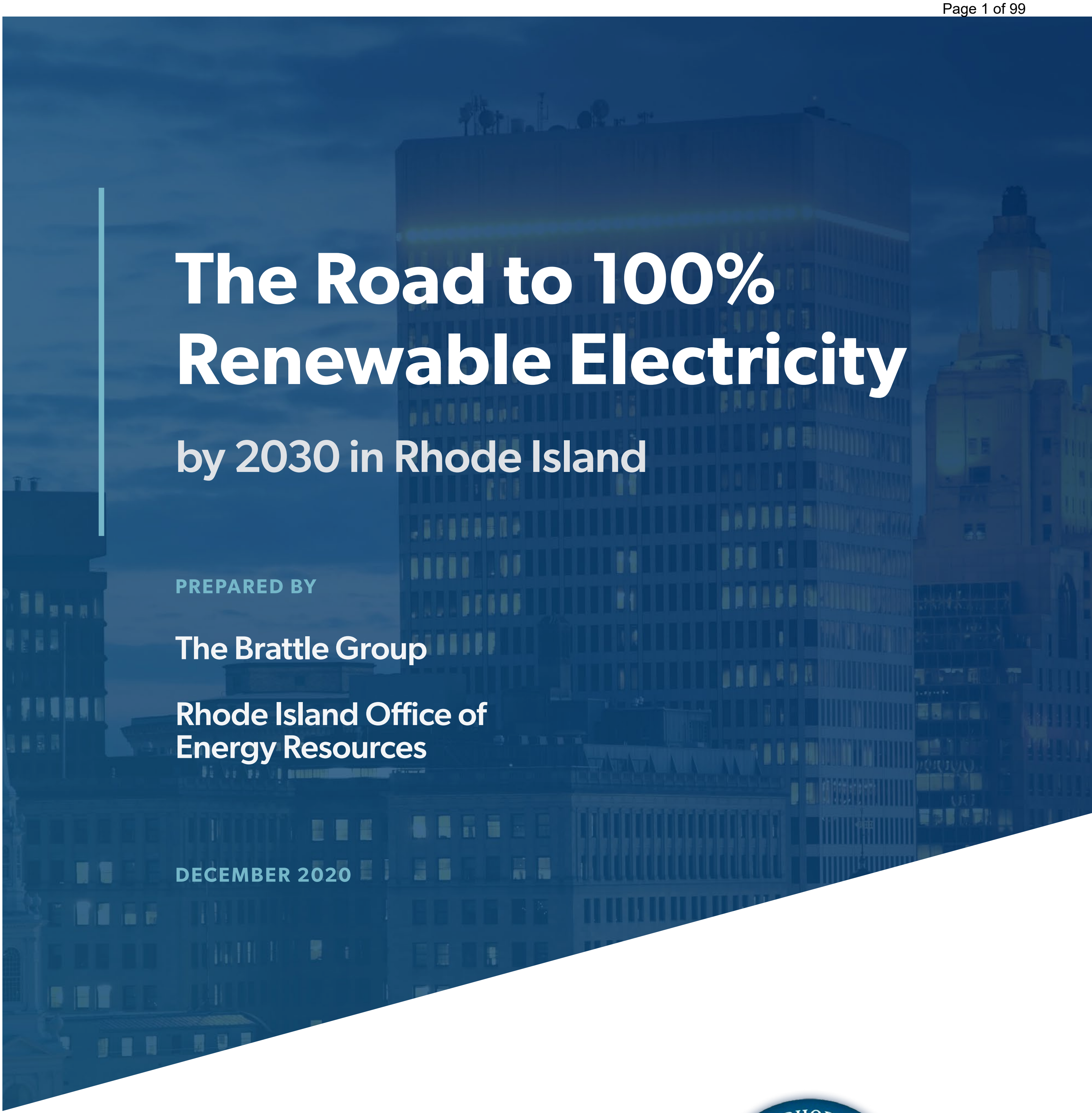
Table 37. Non-rooftop solar potentials: total, low technical, and high technical (MW)

Municipality	Total potential (MW)	Low technical potential (MW)	High technical potential (MW)
Barrington	65.3	13.1	22.4
Bristol	121.3	16.5	61.0
Burrillville	64.5	3.7	32.3
Central Falls	18.9	1.2	3.0
Charlestown	409.1	172.2	294.8
Coventry	140.1	41.7	67.7
Cranston	497.4	43.2	186.9
Cumberland	232.4	10.3	100.3
East Greenwich	231.5	75.8	137.8
East Providence	243.2	52.5	113.2
Exeter	1,021.5	329.4	743.5
Foster	823.2	254.7	603.3
Glocester	248.3	79.3	153.5
Hopkinton	391.2	62.0	247.7
Jamestown	114.9	70.1	72.7
Johnston	832.1	95.3	437.3
Lincoln	216.4	62.3	103.5
Little Compton	52.4	21.9	33.0
Middletown	188.9	18.7	72.2
Narragansett	45.9	22.7	24.8
Newport	166.4	56.0	81.6
New Shoreham	46.8	27.3	28.0
North Kingstown	747.2	122.6	436.6
North Providence	68.9	23.2	25.5
North Smithfield	361.2	10.9	151.8
Pawtucket	140.7	23.3	55.9
Portsmouth	281.7	15.0	106.0
Providence	763.9	99.5	255.1
Richmond	276.7	91.6	181.0
Scituate	60.6	6.7	27.8
Smithfield	317.6	47.3	184.1
South Kingstown	455.4	75.5	238.2
Tiverton	288.7	39.5	176.0
Warren	35.9	1.9	6.9
Warwick	696.2	91.4	264.2
West Greenwich	900.5	314.5	651.4
West Warwick	106.5	17.9	38.1
Westerly	409.8	60.2	200.6
Woonsocket	176.5	1.4	47.7
Total	**12,259.7**	**2,572.4**	**6,667.2**

Table 38. Residential buildings that cannot host solar PV

Municipality	Total number of residential rooftops (thousands)	Fraction of buildings with no buildable area	Number of rooftops with no buildable area	Economic potential (MW)
Barrington	6.4	3%	222	1.3
Bristol	7.0	3%	243	1.5
Burrillville	6.3	5%	300	1.8
Central Falls	2.7	3%	95	0.6
Charlestown	5.2	5%	250	1.5
Coventry	13.6	5%	654	3.9
Cranston	24.8	3%	862	5.2
Cumberland	9.8	3%	340	2.0
East Greenwich	4.6	3%	161	1.0
East Providence	14.3	3%	496	3.0
Exeter	2.3	5%	112	0.7
Foster	2.1	5%	102	0.6
Glocester	3.7	5%	175	1.1
Hopkinton	3.6	5%	170	1.0
Jamestown	2.7	3%	93	0.6
Johnston	9.0	3%	314	1.9
Lincoln	7.0	3%	243	1.5
Little Compton	2.9	5%	141	0.8
Middletown	5.6	3%	195	1.2
Narragansett	8.8	3%	307	1.8
Newport	7.2	3%	251	1.5
New Shoreham	1.7	3%	46	0.3
North Kingstown	9.9	3%	345	2.1
North Providence	9.2	3%	320	1.9
North Smithfield	4.3	3%	148	0.9
Pawtucket	17.5	3%	608	3.7
Portsmouth	7.7	3%	267	1.6
Providence	30.7	3%	926	5.6
Richmond	3.4	5%	163	1.0
Scituate	4.4	5%	213	1.3
Smithfield	6.7	3%	231	1.4
South Kingstown	12.2	5%	586	3.5
Tiverton	6.7	5%	323	1.9
Warren	3.8	3%	133	0.8
Warwick	29.0	3%	741	4.4
West Greenwich	2.0	5%	95	0.6
West Warwick	8.0	3%	277	1.7
Westerly	10.9	5%	522	3.1
Woonsocket	8.5	3%	296	1.8
Total	**326.4**	**-**	**11,965**	**71.8**

Note: This table is intended to facilitate discussion of community solar development, in response to a request from Rhode Island Office of Energy Resources.



The Road to 100% Renewable Electricity

by 2030 in Rhode Island

PREPARED BY

The Brattle Group

Rhode Island Office of Energy Resources

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Brattle

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ABOUT THE RHODE ISLAND OFFICE OF ENERGY RESOURCES (OER)

- OER is Rhode Island's lead energy policy agency, with a mission to guide the state toward a clean, affordable, reliable, and equitable energy future. OER develops policies and programs that respond to the state's evolving energy needs, while advancing environmental sustainability, energy security, and a vibrant clean energy economy. OER is committed to working with public- and private-sector stakeholders to ensure that all Rhode Islanders have access to cost-effective, resilient, and sustainable energy solutions. For more information on OER and Rhode Island's clean energy initiatives, please visit: www.energy.ri.gov.

NOTICE

- This report was prepared jointly by the Rhode Island Office of Energy Resources (OER) and consultants at The Brattle Group. During this project, OER and Brattle received input from state agencies and numerous stakeholders. We wish to recognize staff from the Rhode Island Division of Public Utilities and Carriers (DPUC) and the Department of Environmental Management (DEM) for their insights, and thank those Rhode Island citizens, businesses, and advocacy groups that participated by attending technical workshops and listening sessions, and submitting written comment.
- This report is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors. It does not necessarily reflect those of other clients or other consultants of The Brattle Group.
- We are grateful for the valuable contributions made by OER staff and Brattle team members, including Principal Mark Berkman, Senior Research Analyst Maria Castaner, Research Analyst Megan Diehl, and Research Analyst Shivangi Pant.

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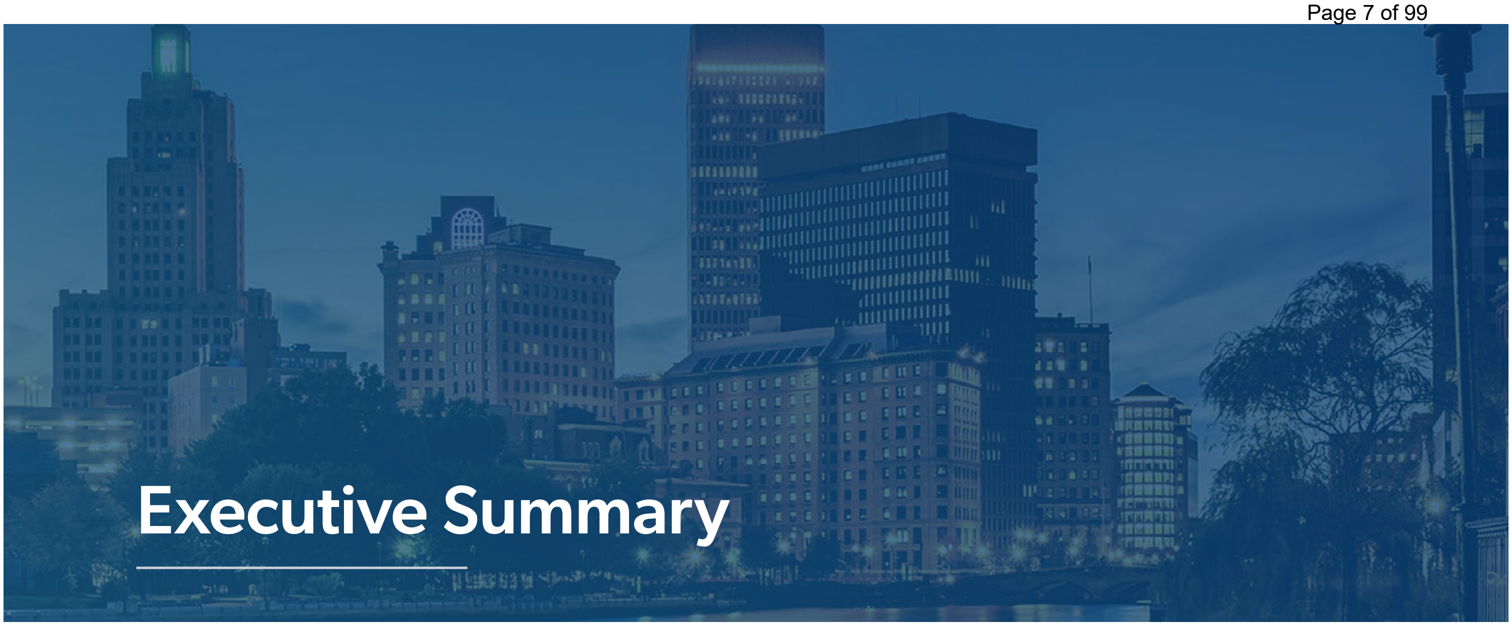

Executive Summary

In January 2020, Governor Gina M. Raimondo signed Executive Order 20-01 that set a first-in-the-nation goal to meet 100% of Rhode Island's electricity demand with renewable energy by 2030.[1] Decarbonizing the electric sector by providing energy from renewable sources is foundational to decarbonizing the Rhode Island economy, and achieving long-term economy-wide greenhouse gas reduction targets consistent with the Resilient Rhode Island Act.[2]

The Executive Order requires Rhode Island's Office of Energy Resources (OER) to conduct economic and energy market analysis and develop viable policy and programmatic pathways to meet this goal. This report is a culmination of the effort by OER and consultants at The Brattle Group to inform the path forward to meeting 100% by 2030, and maintaining 100% thereafter. The project team also engaged relevant state agencies and Rhode Island stakeholders throughout the process through a series of virtual meetings, technical workshops, and listening sessions.

The purpose of the report is first to provide a high-level economic analysis of the key factors that will guide Rhode Island to meeting 100% of the state's electricity demand with renewable electricity by 2030. This study considers the available renewable energy technologies, including their feasibility, scalability, costs, generation patterns, market value, and local economic and employment impacts, as well as barriers that may hamper or slow their implementation. It identifies ways to leverage competition and market information to ensure reasonable ratepayer costs and manage energy price volatility, while taking advantage of economic development opportunities within the state. The report's second objective is to consider specific policy, programmatic, planning and equity-based actions that will support achieving the 100% renewable electricity goal.

To help guide the analysis and the policy recommendations for achieving the goal, the project team developed a set of guiding principles, with input and feedback from stakeholders. The Guiding Principles represent three broad themes: **A)** Decarbonization Principles; **B)** Economic Principles, and **C)** Policy Implementation Principles.

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[1] Governor Gina M. Raimondo, Executive Order 20-01, "Advancing a 100% Renewable Energy Future for Rhode Island by 2030", January 17, 2020.

[2] Rhode Island General Laws §42-6.2, et. seq., the Resilient Rhode Island Act of 2014, establishes greenhouse gas emissions reduction targets of (A) Ten percent (10%) below 1990 levels by 2020; (B) Forty-five percent (45%) below 1990 levels by 2035; and (C) Eighty percent (80%) below 1990 levels by 2050.

Decarbonization Principles

1. Exemplify Climate Leadership
2. Create Incremental Power Sector Decarbonization
3. Facilitate Broader Decarbonization

Economic Principles

4. Pursue Cost Effective Solutions
5. Improve Energy and Environmental Equity
6. Create Economic Development Opportunities

Policy Implementation Principles

7. Ensure Solutions are Robust and Sustainable Beyond 2030
8. Build on Rhode Island's Existing Renewable Energy Mechanisms
9. Be Consistent with Other Rhode Island Priorities and Policies

One of Rhode Island's cornerstone policies for increasing renewable energy in the electricity sector is the Rhode Island Renewable Energy Standard (RES). For the purposes of the analysis, we assume that Rhode Island will track its progress to achieving 100% renewable electricity in 2030 by increasing the RES to 100% in 2030. To achieve the 2030 goal in a manner that aligns with the Guiding Principles, Rhode Island will need to match the 100% RES with programs and incentives that support the development of new renewable energy resources. Rhode Island has a number of well-established programs that support renewable energy generation resources, including the long-term contracting authority granted to National Grid, the Renewable Energy Growth program, the Renewable Energy Fund, and regulations that support net metering and virtual net metering. In addition, Rhode Island has remained committed to its least cost procurement requirements, which drive local investment in cost-effective energy efficiency and demand response measures. With the expected addition of 400 MW of offshore wind capacity from the Revolution Wind project in 2024, Rhode Island is already on pace to support about 3,060 GWh of renewable energy generation in 2030. This equates to about 40% of Rhode Island's projected 2030 electricity demand.

Rhode Island's projected electricity demand in 2030 is about 7,700 GWh, based on our analysis of National Grid's load forecast and trends in energy efficiency and electrification. As shown in **FIGURE ES-1**, Rhode Island will need to add about 4,600 GWh of additional renewable energy to close the remaining renewable electricity gap to reach 100% by 2030, reflecting a relatively flat outlook for electricity demand.[3] This represents a 150% increase in the amount of renewable energy procured to date. The estimated renewable energy gap may be 600-700 GWh larger or smaller, depending on the rate at which the transportation and heating sectors electrify to increase demand and reduce greenhouse gas emissions, and the future progress of energy efficiency efforts that decrease demand.

Rhode Island announced in October 2020 its intent to pursue a competitive solicitation for up to 600 MW of additional offshore wind resources.[4] If the full 600 MW is acquired, the new offshore wind resource would add about 2,700 GWh per year, or about 35% of 2030 electricity demand, filling the majority of the gap. Still further additional renewable energy resources may come from new or expanded programs or procurements or from purchasing RECs from the market to reach 100%.

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[3] To identify the full extent of Rhode Island's path to 100% renewables, as shown in Figure 3 below, we are not accounting for future additions from existing statutory programs (e.g. Renewable Energy Growth) beyond those resources already committed to, but not yet online. We acknowledge that these programs are likely to continue (in some form) throughout the decade and will contribute to closing the gap by 2030. A number of hypothetical resource portfolios, identified later in this report, include a Retail Solar component that reflects continuation or expansion of these programs.

[4] See https://www.ri.gov/press/view/39674

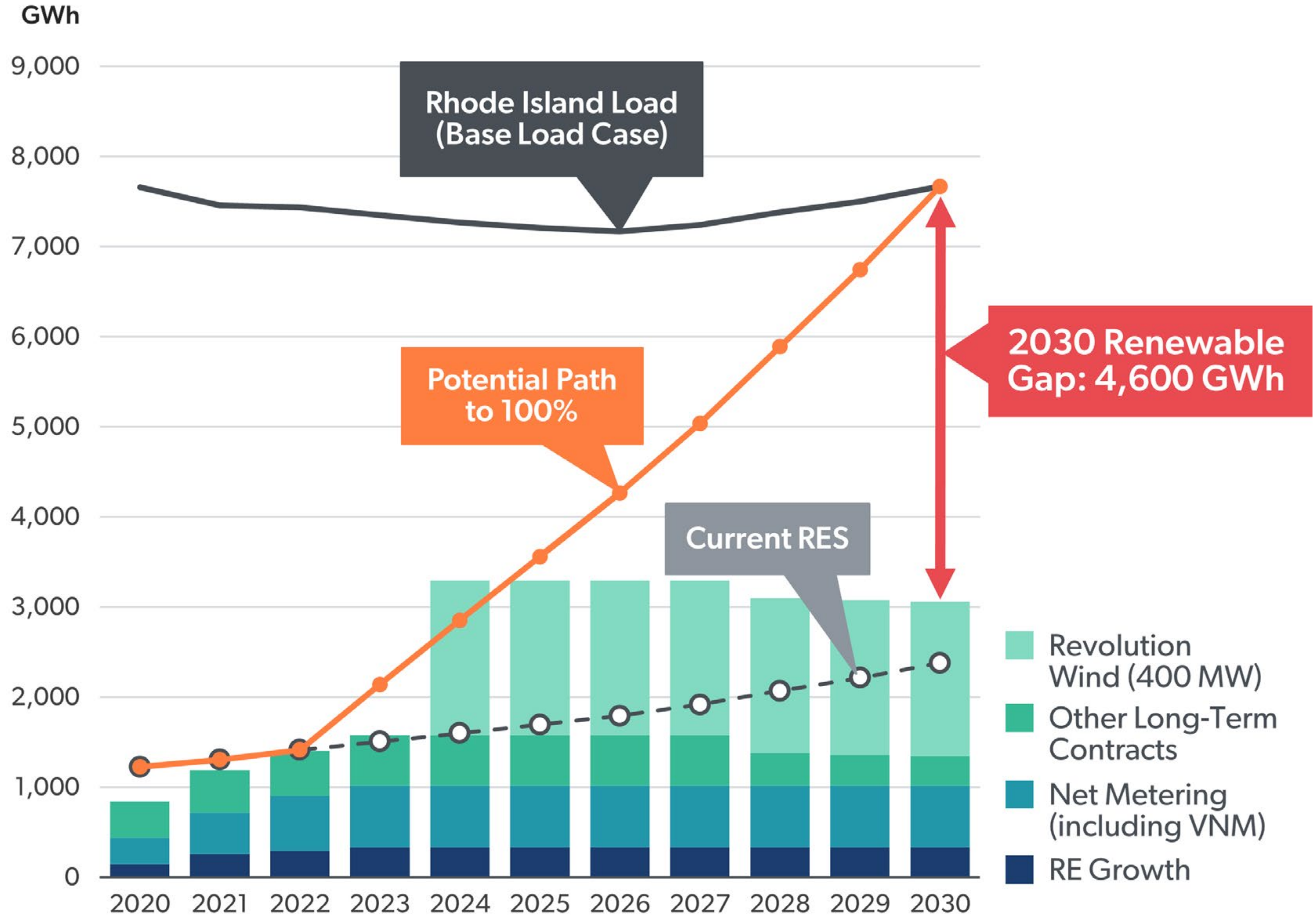

FIGURE ES-1: RENEWABLE ELECTRICITY GAP TO ACHIEVE 100% RENEWABLES

Beyond 2030, Rhode Island will likely need to continue adding renewable energy generation at a similar pace, roughly 400 – 500 GWh per year, due to an expected increase in demand from widespread adoption of electrified heating and transportation. This new electrification load may roughly double total electricity demand in the long run. Rhode Island must also understand the impacts of the increasing decarbonization of the larger New England electricity system. As other states decarbonize their own electricity supplies, the system's greater reliance on intermittent renewable energy resources will increase the challenge of maintaining the short-term balance between electricity generation and demand. Our long-term simulation of the New England electric system indicates that such challenges are likely to still be relatively limited by 2030, but will accelerate in later years as dispatchable fossil generation is increasingly displaced by the rising renewable ambitions of other New England states. Significantly more flexible technologies, such as short-term battery storage and demand resources, will be necessary to maintain short-term balance. As the system becomes highly decarbonized, it will ultimately require additional new technologies for seasonal energy balancing, perhaps including long-term storage technologies and renewable fuels such as methane or hydrogen. These long-term shifts in the regional power system highlight the value to Rhode Island of a renewable energy portfolio whose hourly generation profile offers a reasonably good match to the state's electricity demand profile, which will limit exposure to market prices that will reflect these underlying dynamics and the costs to maintaining system reliability.

Rhode Island has access to several types of renewable energy generation resources to fill the gap and achieve

Technology	Location of Available Resources	Capacity of Each Technology (Needed to Fill Entire 2030 Renewable Energy Gap)	Resource Availability and System Upgrades Required
Offshore Wind	Outer continental shelf off Rhode Island coast	900 – 1,100 MW	Sufficient capacity available in current wind lease areas will require significant offshore and onshore transmission upgrades; more cost-effective upgrades will require regional coordination.
Land-Based Wind	Northern New England and Upstate New York	1,300 – 1,700 MW	Limited potential to fill the gap with New England resources without system upgrades of about $1 billion requiring regional coordination; some capacity may be available in New York, which is building out transmission infrastructure.
Wholesale Solar	On high-voltage transmission system in RI and neighboring states	2,700 – 3,600 MW	2,500 – 6,500 MW of technical potential for ground-mounted solar in Rhode Island, though transmission access may require increasing system upgrade costs; significant additional capacity is in development across New England; land-use concerns remain a significant challenge.
Retail Solar	On lower-voltage distribution system within Rhode Island	3,200 – 4,300 MW	Economic potential of rooftop solar is limited (110 – 260 MW); smaller-scale, ground-mounted facilities connecting to distribution system can fill a portion of the gap, though may face increasing system upgrade costs

TABLE ES-1: CANDIDATE RENEWABLE ELECTRICITY RESOURCES

100% renewable electricity by 2030. Based on our analysis of recently added renewable energy resources and potential for new development, the candidate renewable energy resources are offshore wind, land-based wind, wholesale solar, and retail solar. The availability of each of these resources is summarized in **TABLE ES-1**. We considered other technologies but determined that their limited availability makes them unlikely to play a major role in achieving 100% renewable electricity.

The ratepayer cost impacts and the local economic impacts (GDP, jobs) of achieving 100% renewable electricity are considered first for four Technology Bookends, corresponding to the four candidate technologies. Each Technology Bookend assumes that the 2030 renewable energy gap is filled entirely with one of the candidate technologies. We also analyzed a series of Technology Portfolios that consist of potential mixes of these resources that Rhode Island may consider in pursuing its 2030 goal. We present here the results for the Technology Bookends, highlighting the key takeaways for these technologies that will inform Rhode Island's path forward. Additional results for the Technology Portfolios are presented in **SECTION III.D**.

The ratepayer above-market costs of achieving 100% renewable electricity by 2030 account for both the costs of acquiring the renewable energy resources (which includes the interconnection costs) and the market revenues the resources will earn from the New England electricity market for their energy, capacity and RECs.

- **Resource Acquisition Costs:** The projected costs of the three utility-scale resources—land-based wind, offshore wind, and wholesale solar—are similar to one another, decreasing from about $95 – 100/MWh in the near-term (accounting for the phase-out of the federal tax credits) to about $60 – 70/MWh in 2030 (all in 2020 dollars).[5] The projected 2030 resource acquisition cost is considerably higher for retail solar, $107/MWh in 2030.[6]
- **Energy Market Value:** The energy market value of the renewable energy technologies start relatively low at roughly $20/MWh in 2020, due to current low gas prices. Market values rise as gas prices recover (particularly for wind, which generates most in winter when prices are high), then fall again after 2030 to below $15/MWh on average in 2040, with $0/MWh in many hours due to increasing renewable penetration.
- **Capacity Market Value:** Accounting for recent capacity market results, potential future market designs, and the ability for intermittent resources to contribute to the system's capacity needs, these renewable energy technologies are likely to earn a modest capacity value of $3/MWh to $4/MWh; with range from zero to about $12/MWh reflecting the uncertainty in capacity prices and market design.
- **REC Market Value:** REC prices are difficult to predict, as they are based on the short-term supply-demand balance between state renewable energy mandates and available renewable supply. We assume a Base REC price of $30/MWh and analyze a range of $15/MWh to $45/MWh, consistent with historical REC prices as well as the net costs of acquiring utility-scale renewables.

FIGURE ES-2 compares the four Technology Bookends, showing the estimated above-market costs of achieving 100% renewable electricity entirely with each one of the four candidate technologies. The figure shows the net present value (NPV) of 2020 to 2040 above-market costs,[7] with the labeled point reflecting Base Case cost assumptions, and the bar reflecting the uncertainty in renewable acquisition costs. The net costs of the three utility-scale Technology Bookends are quite similar, with Base Case above-market costs of $1,900 million to $2,100 million and largely overlapping cost ranges. The Retail Solar Bookend results in materially higher above-market costs of $4,500 million, reflecting its significantly higher resource cost. As a reference point, the cost of market REC purchases is shown at the top of the figure, where $30/MWh RECs could fill the entire renewable energy gap at a cost $1,400 million. However, purchasing market RECs would provide uncertain and potentially limited additional GHG emissions reductions, and may not provide local economic development benefits.

The similar cost estimates and ranges across the utility-scale resources signal that all these technologies are competitive, with none dominating. Over the next decade, the costs of the different resource types could diverge, based on global and local markets for each resource, the local labor market, the need for system upgrades, and the approach

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[5] At the time of the analysis, the federal production tax credit and investment tax credit were scheduled to phase-out over the next few years. In late December 2020, the U.S. Congress extended the tax credits for 2-3 years. However, we were unable to reflect these changes in our analysis in time for the final report.

[6] Retail solar costs are a capacity-weighted average of the costs of distribution-connected solar resources, ranging from 10 kW residential rooftop resources to 5 MW ground-mounted resources. The mix of solar resources is consistent with the 2020 capacity allocation for the Renewable Energy Growth program.

[7] Net present value is as of 2020 and calculated using a 3% (real) discount rate. All monetary values throughout the report are in 2020 dollars, unless otherwise noted.

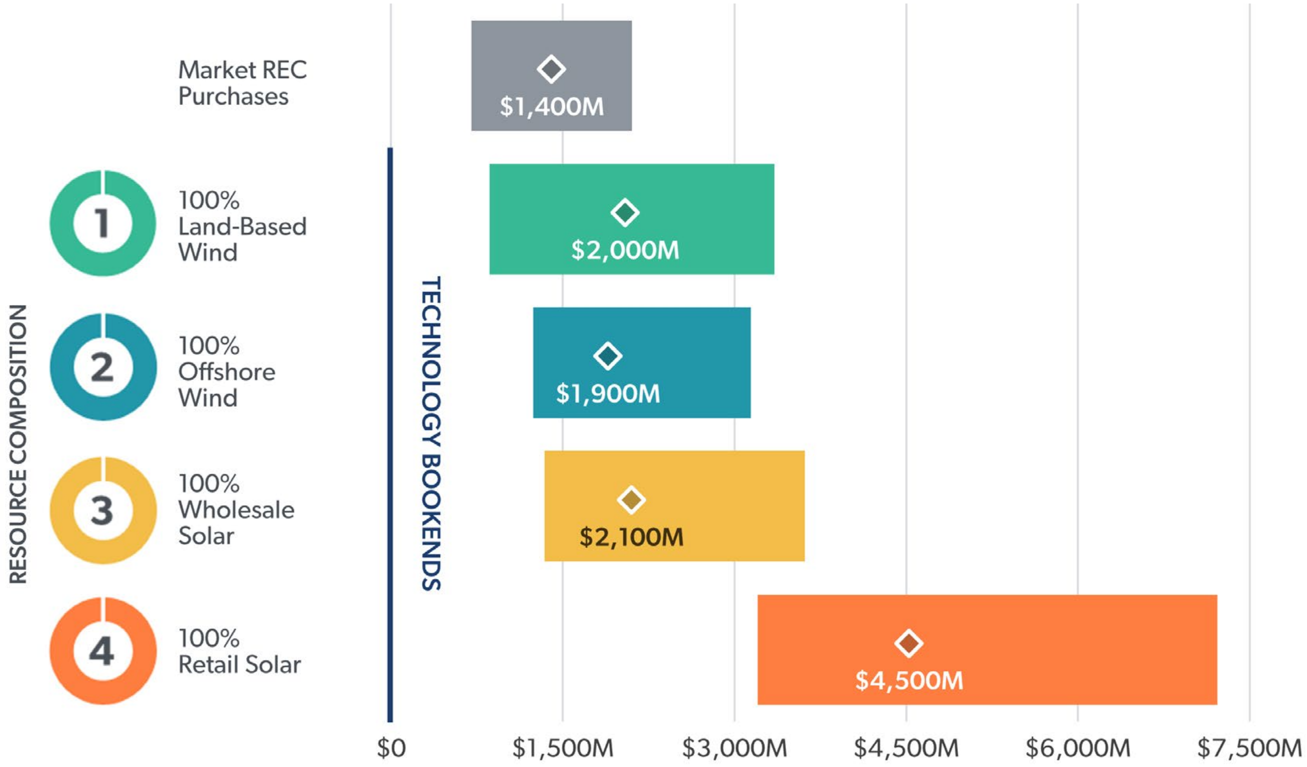

FIGURE ES-2: NPV OF ABOVE-MARKET COSTS (2020–2040) OF ACHIEVING 100% RENEWABLES; BOOKENDS
(NET OF ENERGY AND CAPACITY REVENUES, NOT REC REVENUES)

Rhode Island and other states take for planning the future regional power system. The cost diversity that has been observed across specific projects is also likely to continue. It will be valuable for Rhode Island to continue to seek out opportunities to foster competition among these resources, across types as well as within them, to identify the particular technologies and projects that are most attractive for the state to reach 100% renewable electricity. Retail solar is significantly higher cost, though as seen below, offers greater local economic benefits.

Of course, these similar costs suggest that the retail rate impacts of the three utility-scale Technology Bookends are also similar, at roughly 2 cents/kWh (range 1 to 5 cents/kWh) in 2030, while the retail solar impact is higher at 6 cents/kWh (range 4 to 11 cents/kWh), as shown in **FIGURE ES-3**. These rate impacts would increase a typical monthly residential bill in 2030 by about $11 to $14 with utility-scale renewables, or by $30 if the entire gap were to be filled with retail solar.

We also analyzed the local economic impacts of these renewable energy resources – their effect on Rhode Island's gross domestic product (GDP) and in-state employment. This impact occurs through three potential channels:

1. **Construction Expenditures** before in-state projects come online;
2. **O&M Expenditures** during operation of in-state projects; and,
3. **Tariff Impacts paid for by Rhode Island ratepayers** throughout the life of the resource or contract.

For this second set of metrics, we take a relative perspective – comparing the impacts of meeting the 100% goal with the Technology Bookends versus meeting it entirely by purchasing RECs from the New England market at an assumed REC price. That is, this perspective does not reflect the overall economic impact of accelerating the RES to achieve 100% in 2030, but rather considers the impact of how 100% is achieved relative to meeting it with market REC purchases. In the body of the

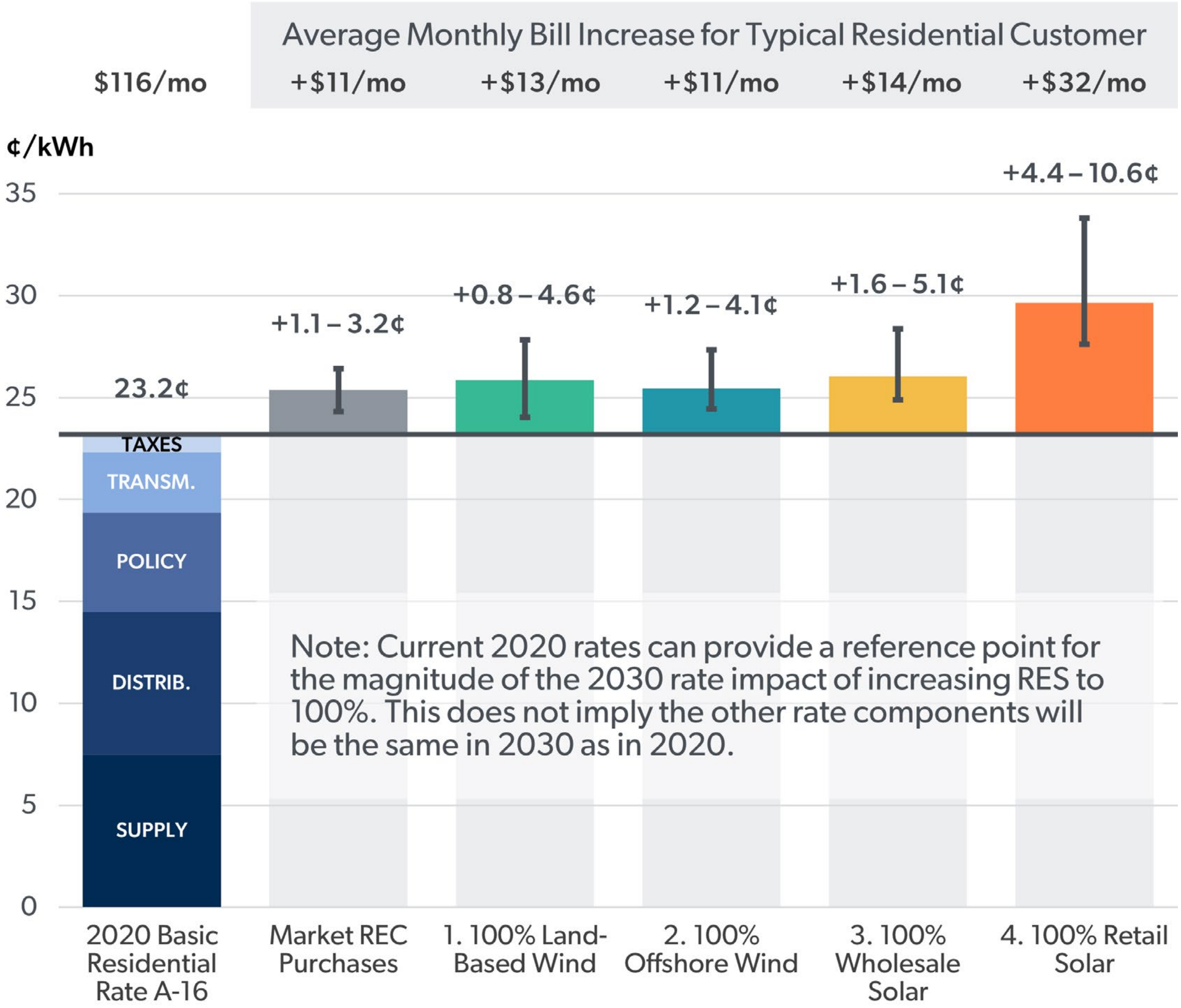

FIGURE ES-3: 2030 RATE IMPACTS OF 100% RENEWABLE ELECTRICITY

Notes: Assumes typical residential customer consumes 500 kWh/mo.

report, and in greater detail in the accompanying Technical Support Document, we show how the economic impacts evolve over time. For in-state resources, the economic benefits of construction expenditures precede the resource coming online, followed by the tariff impacts (which may be positive or negative, depending on the cost of the resource relative to the assumed REC price) and the O&M impacts.

FIGURE ES-4 shows the NPV of GDP impacts for each of the Technology Bookends. Much information is included in this figure, including the range of uncertainty due to resource cost (the length of each bar), the REC price used as a comparison value (from one bar to the next) and comparing in-state technologies (solid bars) versus out-of-state technologies (outline bars). Of course, any technology's economic impact is better when compared to a higher REC price, and the impact is more positive at low resource cost than at high. The key insights here are that in-state resources have generally positive impacts relative to REC purchases, while out-of-state ones have lower and often negative impacts, and also a wider range of impacts.

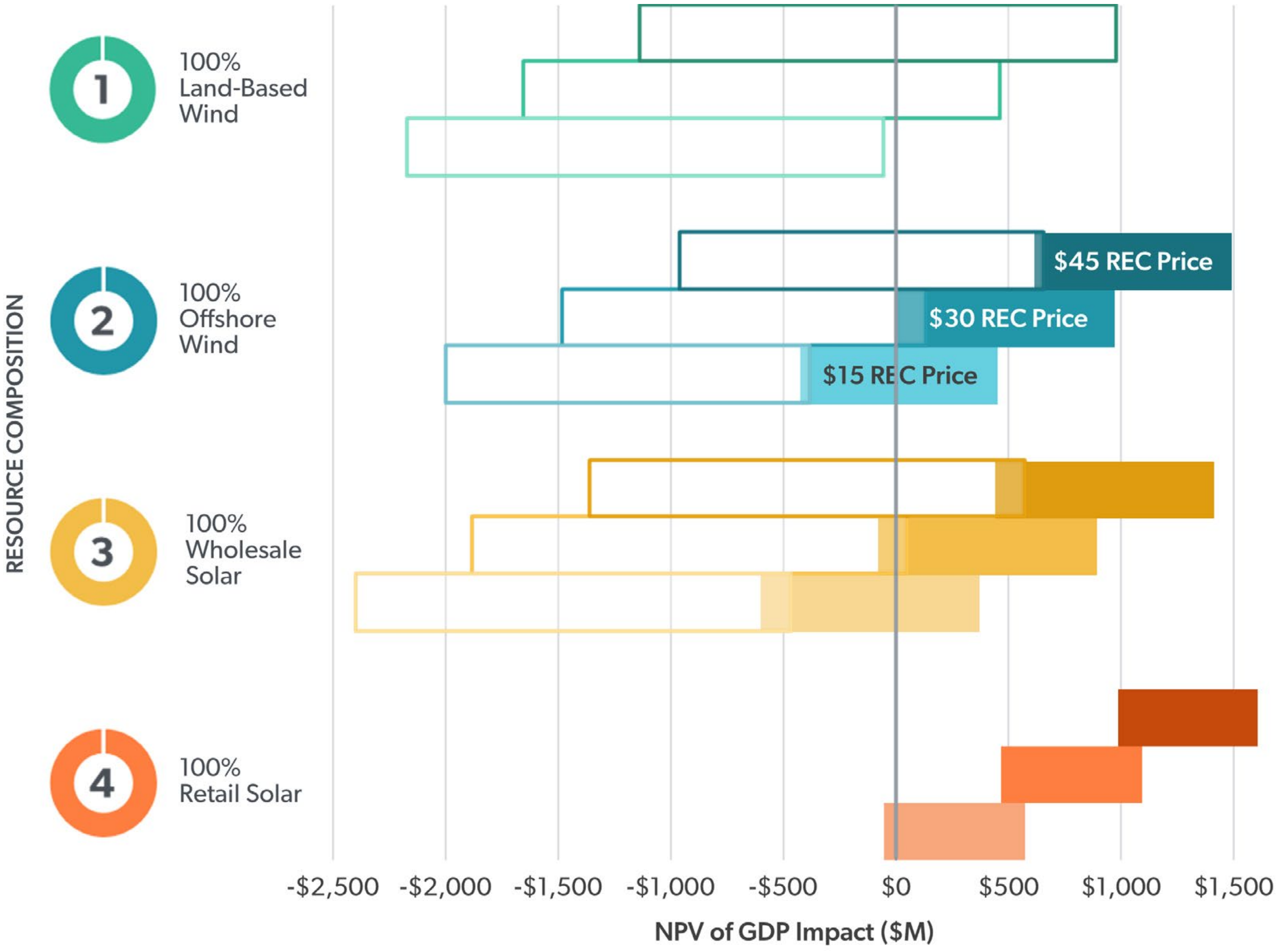

FIGURE ES-4: NPV OF RHODE ISLAND GDP IMPACT (2020–2040) WITH UNCERTAINTIES; BOOKENDS

This is because in-state resources give an economic boost to the Rhode Island economy via in-state construction and operating expenditures; out-of-state resources do not share these. Thus retail solar, which is more costly and has a negative economic impact due to higher costs to ratepayers, has a net economic impact that is comparable to other in-state resources due to the offsetting effect of higher in-state expenditures and the fact that a larger share of each dollar invested for retail solar enters the local Rhode Island economy.[8]

The two primary metrics considered here tell somewhat different stories: above-market cost draws a distinction between utility-scale resources (which all have similar cost ranges) versus higher-cost retail (distributed) solar. But the primary differences seen in the economic impact analysis are between in-state resources, which all have similar, mostly positive impacts (including the more costly retail solar resource), versus out-of-state resources, which have lower and often negative economic impacts. The Technology Portfolios presented in the report come to similar conclusions: ratepayer above-market costs rise with increasing levels of retail solar; economic impacts primarily depend on the mix of in-state and out-of-state resources.

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[8] Our analysis here uses typical allocations of expenditures to economic sectors for each resource type. The actual local Rhode Island impact of any particular project will depend on how that project is executed, including its mix of local vs out-of-state suppliers and labor. We also assume that an out-of-state project will have no in-state impact, though in fact, because of interdependent supply chains in New England, a project located outside of Rhode Island may have some in-state benefits to the extent it utilizes materials, suppliers or labor from Rhode Island.

We summarize here the key insights from the analytic portion of the study.

- Rhode Island's goal of 100% renewable electricity by 2030 is achievable. Renewable resources are available within Rhode Island and in surrounding areas to support this goal.
- Achieving 100% renewable electricity by 2030 will not be costless. Ratepayers will need to support investments driving long-term energy, economic, and environmental benefits. In the near term, renewable electricity will cost more than fossil-fired generation, and utility bills will be higher regardless of the composition of the ultimate portfolio of renewable resources. But net economic and energy benefits and costs will be determined by how that portfolio is shaped over time.
- The existing REC structures, tracking mechanisms, and markets will allow Rhode Island to implement the 100% goal seamlessly, track its progress, and accommodate uncertainty and variability in electricity demand and renewable generation.
- Rhode Island should limit the extent to which it relies on short-term REC purchases to meet its 100% renewable goal to ensure that it will truly achieve incremental GHG reductions, and to limit the ratepayer cost impact of potentially volatile REC prices.
- All renewable energy resource types will require integrated planning and investment to build out the necessary infrastructure (the local distribution system, onshore and offshore transmission facilities, as well as the renewable generation itself) to achieve 100% cost-effectively. Different resources will require different investments, and this effort will take significant time, collaboration, and upfront investment.
- Utility-scale offshore wind, land-based wind, and solar resources are likely to be the lowest costs to ratepayers. Distributed solar resources have significantly higher above-market costs, and can also result in significant shifts between ratepayers if acquired through net metering programs. However, each of these resources types present varying levels of in-state economic development and job growth potential. Available market data and cost projections also show significant and overlapping cost uncertainties for each of these.
- In-state renewable energy resources, including offshore wind in adjacent Federal waters and higher cost retail solar, provide material local economic benefits relative to out-of-state resources and/or market purchases of RECs. The higher ratepayer costs of retail solar are partially offset by greater local economic benefits, leading to similar impacts on overall state GDP as in-state utility-scale resources. However, the GDP benefits and costs do not accrue to the same populations; retail solar will result in greater shifts of costs and benefits within the Rhode Island economy.
- Rhode Island can identify the lowest cost resources by proactively planning the system upgrades necessary to achieve 100% and procuring renewable energy resources through competitive procurements and programs. Participating in multi-state solicitations may make it possible for Rhode Island to access the economies of scale of larger projects.
- Rhode Island can reduce ratepayer costs and risks by collaborating with other New England states to update the design of regional electricity markets to account for the full value of renewable energy resources to the system.
- For the longer term, Rhode Island should consider acquiring a renewable portfolio that is a reasonable match for its hourly load profile. This will contribute to achieving the proper long-term balance across the region, and will reduce energy price risk and the costs of balancing supply and demand for Rhode Island ratepayers. With anticipated demand shapes, a portfolio of mostly wind with up to about 30% solar offers a reasonable hourly match.
- To achieve and maintain 100% renewable electricity beyond 2030, policy, programmatic and technical (e.g. storage, demand management) solutions may need to evolve, as the regional penetration of clean energy resources accelerates and increasingly-challenging grid impacts emerge. There will likely be significant increases in the overall amount of energy needed to meet new electrification loads from the transportation and heating sectors, mostly beyond 2030.

Grounded in the three main components of this project – analysis, guiding principles, and public engagement – the Office of Energy Resources and consultants at The Brattle Group developed a set of recommendations and action steps for 2021 and beyond to advance Rhode Island toward a 100% renewable electricity future.

We categorize our recommendations into three segments: **Policy**, **Planning & Enabling**, and **Equity** and summarize the recommendations in the table below.

TABLE ES-2: RECOMMENDATIONS SUMMARY

TOPIC	RECOMMENDATION
POLICY RECOMMENDATIONS	
Renewable Energy Standard	Amend the state's RES to require 100% renewable electricity by 2030.
Energy Efficiency and Demand Response	Extend Least-Cost Procurement of energy efficiency and demand response beyond 2023 to at least 2030.
Balance of Wholesale and Retail Renewable Electricity	Develop market-driven approaches that allow for cross-technology competition where appropriate. Support continuation of the Renewable Energy Growth (REG) program and net metering (NM), contingent on identification and integration of measures to improve sustainability, affordability, and equity. Commence a forum for stakeholder dialogue and consensus-building on the long-term costs and benefits of the state's net metering construct. Extend the Renewable Energy Fund (REF) beyond its current 2022 sunset. Support the burgeoning offshore wind industry that will be critical to the Rhode Island clean energy economy and a decarbonized future for the region.

TOPIC	RECOMMENDATION
PLANNING AND ENABLING RECOMMENDATIONS	
Integrated Grid Planning	Consider key drivers of system needs, such as distributed renewable energy and electrification, over longer time horizons to better understand and plan for changing future system needs. Analyze transmission and distribution system needs for several 100% renewable energy scenarios to identify potential grid challenges and development opportunities. Initiate a collaborative effort with National Grid, state agencies, municipalities, and other key stakeholders to explore the potential for a more integrated approach to grid planning beginning in 2021. Explore how we might collectively enhance grid visibility and improve forecasting.
Power Sector Transformation	Improve forecasting and implement a stakeholder engagement plan during forecast development. Consider strategies to compensate the value of distributed energy resources based, in part, on their location, and how those incentives align with more proactive distribution system planning. Advance electrification that is beneficial to system efficiency and greenhouse gas emission reductions. Consider opportunities for developing performance incentive mechanisms.
Energy Storage and Demand Management	Develop a Rhode Island-centric strategic plan for the role of energy storage and demand management as renewable deployment increases through 2030 and beyond. Explore the role of programs and incentives in achieving optimal, cost-effective energy storage penetration at beneficial locations on the grid, as well as how demand management capabilities can be acquired and sited.
Regional Collaboration on Markets and Transmission	Continue coordination with other New England states on wholesale market designs and transmission planning processes that facilitate energy decarbonization and renewable resource integration across the region Coordinate with other New England states on transmission planning processes to better facilitate energy system transformation and proactively plan for the integration of large-scale resources and distributed energy resources across the region. Identify and implement wholesale market mechanisms that fully account for the value of existing and future state-level investments in renewable resources and meet states' decarbonization mandates and maintain resource adequacy at the lowest possible cost.

TOPIC	RECOMMENDATION
EQUITY RECOMMENDATIONS	
Community Partnerships	Partner with and listen to frontline communities about their needs and goals in the clean energy transition. Target community-based training efforts to support in-demand clean energy jobs. Provide education about the opportunities and challenges available in creating clean energy programs and policies, and information about energy programs, including comparative costs and benefits.
Equity Metrics	Develop metrics to track progress toward community-identified equity outcomes.
Improve Community-Determined Outcomes	Improve outcomes identified and prioritized by communities through rate design, program adjustments, and policy. Reduce barriers to participation through effective and culturally competent program design and delivery. Reduce financial burdens and provide support for low- and moderate-income households and frontline communities beyond installing technology, including structures for aiding with upkeep and services.

I. Introduction and Approach

I.A Background and Motivation

Consistent with well-established scientific consensus and international commitments such as the Paris Accord, Rhode Island has committed to deep economy-wide decarbonization by 2050.[1] Acknowledging the state's position on the front lines of climate change, including 400 miles of coastline, The Resilient Rhode Island Act of 2014 established a goal of 80% economy-wide greenhouse gas ("GHG") emissions reductions relative to a 1990 baseline by 2050, with interim targets of 10% reductions by 2020, and 45% by 2035.[2] As a vital step toward meeting this commitment, Governor Gina M. Raimondo's Executive Order 20-01 signed January 17, 2020 called for a plan to rapidly decarbonize the state's electricity sector, establishing a nation-leading goal to acquire 100% of its electricity from renewable energy sources by 2030.[3] It required the Rhode Island Office of Energy Resources (OER) to conduct economic and energy market analysis and develop viable policy and programmatic pathways to meet this goal, providing a report to the Governor with a specific and implementable action plan by the end of 2020.

Decarbonizing the electricity sector is likely to be foundational to decarbonizing the Rhode Island economy more broadly. **FIGURE 1** shows that electricity consumption accounts for just over a quarter of Rhode Island's current total greenhouse gas emissions. Residential and commercial heating together make up another quarter, and transportation accounts for over a third of the total. Beneficial electrification – replacing direct fossil fuel use with electricity to cost effectively reduce overall emissions – combined with decarbonizing the power grid offers some of the most promising pathways for decarbonizing other major carbon-emitting sectors. Electric vehicles present an opportunity to displace petroleum-based motor fuels, and electrifying heat with heat pumps can displace the burning of natural gas and heating oil in residential and commercial buildings. Other smaller applications that combust fossil fuels directly can also be electrified – gas-fired water heaters, stoves, clothes dryers, etc.

If pursued in these other sectors, electrification could double electricity demand in New England and Rhode Island over the next few decades, while displacing most of the region's direct fossil fuel use. By the time Rhode Island achieves its 100% renewable electricity goal in 2030, electrification-induced load growth will likely be just beginning in earnest. As electrification accelerates beyond 2030, load will rise

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[1] Rhode Island has reaffirmed its commitment to the principles of the Paris Climate Agreement. "Executive Order 17-06, Reaffirming Rhode Island's Commitment to the Principles of the Paris Climate Agreement," State of Rhode Island and Providence Plantations. June 12, 2017. http://www.governor.ri.gov/documents/orders/ExecOrder_17-06_06112017.pdf

[2] Resilient Rhode Island Act of 2014 – Climate Coordinating Council, Chapter 42-6.2. http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM

[3] Governor Gina M. Raimondo, Executive Order 20-01, "Advancing a 100% Renewable Energy Future for Rhode Island by 2030", January 17, 2020.

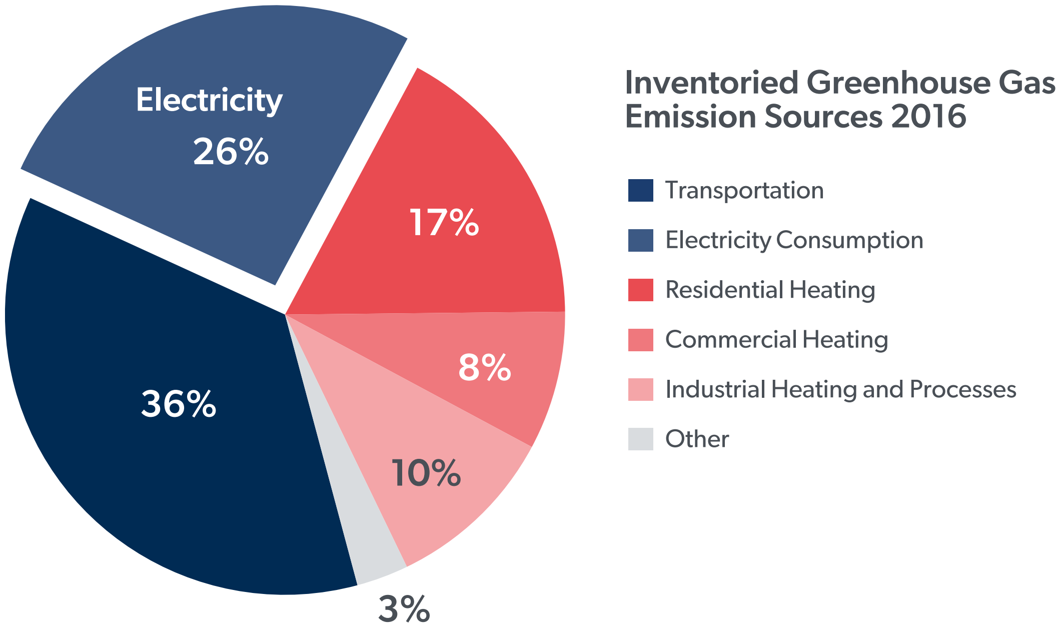

FIGURE 1: COMPOSITION OF RHODE ISLAND GHG EMISSIONS

Source: Rhode Island Department of Environmental Management, Rhode Island's 2016 Greenhouse Gas (GHG) Emissions Inventory Update, EC4 Meeting, September 12, 2019.

sharply, and Rhode Island will need to add considerably more new renewables to maintain its 100% renewable share.[4]

Rhode Island already has a renewable energy requirement, its Renewable Energy Standard (RES), originally implemented in 2004. This standard is based on energy produced and consumed, and requires that a specified percentage of the total obligated electricity consumption in the state must come from renewable sources, on an annual basis. Compliance with the RES is tracked through the creation and retirement of Renewable Energy Certificates (RECs). The existing Rhode Island RES legislation started in 2004 with a lower renewable requirement, but was revised in 2016 to 10.0% in that year, rising at 1.5% per year. In 2020, the RES requires that energy corresponding to 16.0% of total load must come from qualified renewable sources; this continues to increase at 1.5% per year until it reaches 38.5% in 2035.

This effort to rapidly transition Rhode Island's electricity supply to renewable sources is informed by and will interact with a broader set of state-level initiatives and inter-state coordination that focuses on decarbonizing the state's primary emitting sectors. These include the implementation of least-cost procurement and energy efficiency programs; Rhode Island's Heating Sector Transformation initiative;[5] the state's longtime participation in the Regional Greenhouse Gas Initiative (RGGI); its role in the Transportation and Climate Initiative (TCI); and its recent exploration of a broader carbon pricing program.[6] Recently evolving science and evidence regarding climate change suggests that it may be

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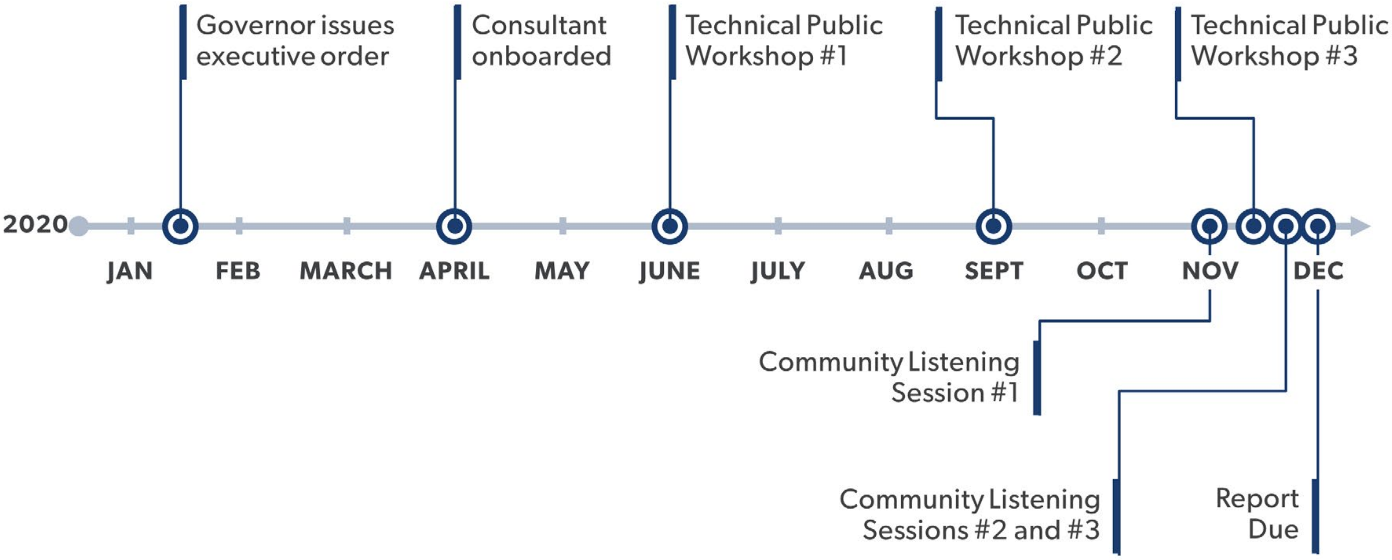
[4] Jurgen Weiss and J. Michael Hagerty, Achieving 80% GHG Reduction in New England by 2050, Prepared for the Coalition for Community Solar Access, September 2019.

[5] Dean Murphy and Jurgen Weiss, Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050, Prepared for the Rhode Island Office of Energy Resources and Division of Public Utilities & Carriers, April 22, 2020.

[6] See: http://www.energy.ri.gov/carbonpricingstudy/



necessary to accelerate decarbonization goals even beyond the 80% by 2050 target currently in effect for Rhode Island and numerous other jurisdictions.[7] Rhode Island's quick transition to renewable electricity will help to enable more rapid decarbonization within the state, as well as offering some protection against challenges that may arise if weaning some particular sectors and uses from fossil fuels is more difficult or slower than expected.

I.B Project Team and Stakeholder Engagement

To carry out the Governor's Executive Order, OER engaged consultants at The Brattle Group to analyze the impacts of achieving 100% renewable electricity by 2030 and assist in the development of policies and pathways.

A key component of this effort consisted of broad and extensive stakeholder engagement, designed to learn from stakeholders, to engage them in the process, and to inform them of technical findings as the project progressed. A summary of the stakeholder engagement process and key questions and comments raised by stakeholders is included in the **APPENDIX**. The process included interviews with a wide range of stakeholders to provide early input into the scope and objectives of the study. Three public technical workshops were held over the course of the project to share information, present intermediate results, and collect feedback; the draft materials for these workshops was made publicly available.[8] OER also held three community listening sessions to provide additional opportunities for the public to provide their input on the findings of the study. Stakeholders were encouraged to provide written feedback throughout the process. Stakeholders were encouraged to provide written feedback throughout the process.

I.C Objectives and Approach

The purpose of this study is to provide a high-level analysis that will help guide Rhode Island to meeting 100% of the

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[7] The U.N. Emissions Gap Report 2020 states that commitments to achieve net-zero emissions by mid-century are "broadly consistent with the Paris Agreement temperature goals." United Nations Environment Programme, Emissions Gap Report 2020, 2020.

[8] See: www.energy.ri.gov/100percent/

state's electricity demand with renewable energy resources by 2030. This study considers the available renewable energy technologies, including their feasibility, scalability, cost, and local economic and employment impacts, as well as barriers that may hamper or slow their implementation. It identifies ways to leverage competition and market information to ensure reasonable ratepayer costs and manage energy price volatility, while taking advantage of economic development opportunities within the state. It also considers specific policy, programmatic, planning and equity-based actions that will support the 100% renewable electricity goal.

The primary steps in completing this analysis included the following steps:

1. Solicit stakeholder input and feedback early and throughout the process;
2. Define the 100% renewable electricity goal;
3. Identify the current gap in achieving 100% renewable electricity by 2030 and then maintaining 100% renewable electricity beyond 2030;
4. Identify candidate renewable energy technologies that could play a major role in filling the 2030 renewable energy gap, considering the availability of each technology;
5. Estimate the net costs of the candidate renewable energy technologies, including the costs of the generation technologies, the associated system upgrade costs, and their energy, capacity, and REC market value;
6. Analyze the total above-market costs and local economic impacts of filling the entire 2030 renewable energy gap with one of the candidate renewable energy technologies, which we refer to as Technology Bookends;
7. Define Technology Portfolios, potential combinations of renewable energy technologies to fill the gap to 100%, and similarly analyze the total above-market costs and local economic impacts of each Portfolio, as well as additional factors that might affect their attractiveness;
8. Summarize the key analytical insights to inform the policy and programmatic recommendations to achieve 100% renewable electricity by 2030; and,
9. Develop policy and programmatic recommendations to support achievement of the goal based on the key analytical insights, stakeholder input, and an understanding of Rhode Island's existing suite of clean energy and environmental policy goals.

One of the primary objectives of achieving 100% renewable electricity is to reduce GHG emissions. Each of the Technology Bookends and Portfolios in the analysis achieves 100% renewable electricity by 2030 on a consumption basis. Thus, all of the options considered reduce GHG emissions attributed to Rhode Island electricity demand to zero by 2030. For this reason, the analysis does not identify impacts on GHG emissions as a distinguishing factor across the Technology Bookends and Portfolios.

The study was carried out amid the COVID-19 pandemic, which has severely disrupted much of the state, national and international economy, including the energy sector. Despite the near-term impacts of the pandemic, we believe that it will not fundamentally alter the long-term, system-wide needs and goals for decarbonizing the electricity sector and ultimately the entire economy. The imperative to address climate change by decarbonizing the power sector and the larger economy will still exist long after the pandemic has abated. However, near-term increases in the development of in-state renewable energy resources can play a role in accelerating the economic recovery from the impacts of the pandemic.

A Technical Support Document accompanies this report, providing additional detail on the modeling and assumptions that underlie the analytic findings.

I.D Guiding Principles for 100% Renewable Electricity Study

As an early part of this effort, the project team developed a set of principles, with input and feedback from stakeholders, to help guide the analysis and the policy recommendations for achieving the 100% renewable electricity goal. The Guiding Principles identified the important role a decarbonized electric power sector will play in achieving economy-wide decarbonization goals, clarified the key metrics for analyzing alternative paths to achieving the goal, and focused the implications of the analysis on the primary changes necessary to achieve the goal.

The Guiding Principles represent three broad themes: **A)** Decarbonization Principles; **B)** Economic Principles, and **C)** Policy Implementation Principles. These Guiding Principles can conflict with each other in some circumstances, requiring tradeoffs among them. For example, an approach that supports new renewable generation resources and clearly achieves fully additional GHG reductions may be more costly than an alternative that takes advantage of renewable energy that already exists, and thus may not actually advance decarbonization goals. These Guiding Principles are summarized on the next page.

Guiding Principles

A) Decarbonization Principles

1. **Exemplify Climate Leadership**
    - Set goals consistent with avoiding the worst implications of climate change
    - Provide an example to states attempting to achieve similar targets
2. **Create Incremental Power Sector Decarbonization**
    - GHG reductions should be "additional" – beyond what would occur otherwise
    - Verifiable, e.g., with NEPOOL-GIS tracking
    - Account for load met by behind-the-meter generation, as well as metered load
3. **Facilitate Broader Decarbonization**
    - In other sectors (transportation, heating), and beyond Rhode Island
    - Collaborate with regional partners to maximize GHG reductions

B) Economic Principles

1. **Pursue Cost Effective Solutions**
    - Lowest reasonable costs to consumers
    - Leverage market competition to reduce ratepayer costs and energy price volatility
    - Maintain affordability of electricity for all Rhode Islanders
2. **Improve Energy and Environmental Equity**
    - Improve equitable outcomes as prioritized by communities
3. **Create Economic Development Opportunities**
    - Foster opportunity in Rhode Island's clean energy economy

C) Policy Implementation Principles

1. **Ensure Solutions are Robust and Sustainable Beyond 2030**
    - Continue to achieve 100% renewable electricity to 2050 and beyond, at lowest reasonable cost
    - Flexible in response to growing electrification load, market and technological uncertainties and surprises
    - Consider early adoption of "integration" resources (batteries, long-term storage, DR, etc.)
2. **Build on Rhode Island's Existing Renewable Energy Mechanisms**
    - Align with and leverage Rhode Island's existing programs and laws
3. Be **Consistent with Other Rhode Island Priorities and Policies**
    - Responsible siting: balancing conflicting demands with open space, housing, etc.
    - Social and economic policies: labor, housing, economic development, etc.
    - Ensure continued power system reliability

II. Rhode Island's 100% Renewable Electricity Goal

II.A Rhode Island's 100% Renewable Electricity Goal and the New England Electricity System

To understand how Rhode Island will achieve its 100% renewable electricity goal by 2030, it is necessary to first understand Rhode Island's electricity system and how it interacts with the larger New England grid.

At a high level, the Rhode Island electricity system can be divided into the high-voltage transmission system and lower-voltage distribution system:

- The high-voltage transmission system in Rhode Island is a portion of the larger, highly interconnected transmission network that spans all six New England states and connects to neighboring systems in New York and Canada. The transmission system connects electricity produced by generation facilities across the region to the local distribution systems in each state. Rhode Island and the other states rely on ISO New England (ISO-NE), an independent, non-profit Regional Transmission Organization, to operate the regional transmission system and wholesale electricity markets.
- The lower-voltage distribution system in Rhode Island is primarily a radial system that receives electricity from the regional transmission system and local distributed generation resources, and delivers it to customers throughout the state. National Grid owns, plans, and operates the distribution system for most of Rhode Island.[9]

The regional transmission system provides Rhode Island's load serving entities—which include National Grid and many third-party electricity providers—and their customers access to generation resources across a wider region, and gives generation resources in Rhode Island access to customers across New England. For instance, a distribution utility in Rhode Island may contract for electricity generation from a hydroelectric resource in Maine. Under such an arrangement, the hydro plant injects power into the regional high-voltage transmission system in Maine, and a corresponding amount of power is withdrawn at local substations in Rhode Island. At the local substations, the voltage is lowered and the power is delivered across the distribution system to individual customers. Suppliers may also purchase power from the ISO-NE operated wholesale electricity markets.

The New England states have implemented clean energy policies that will increase renewable energy resources in the

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[9] Two municipal-centric electric utilities also operate in Rhode Island – the Pascoag Utility District (in Burrillville) and the Block Island Utility District (providing service for New Shoreham). These utilities represent less than 1% of total statewide electric demand.

New England Electricity System and Markets

Rhode Island is part of the New England power system, which is managed by ISO New England, an independent, non-profit Regional Transmission Organization. Wholesale power is produced by generators and flows across the regional interstate transmission network. It is delivered to distribution utilities, referred to as Electric Distribution Companies, or EDCs (National Grid is Rhode Island's largest EDC). The EDC's distribution system delivers the power to the customer's premises where it is metered and consumed. Customers may purchase the power itself from a third-party provider (an electricity reseller who generates power or buys it at wholesale from other generators, and resells it to customers at retail), or they can purchase it from the EDC via "default service" at a regulated rate. In either case, customers pay the EDC's regulated delivery charge for the delivery service.

Electricity consumption varies considerably with time of day, season, weather, etc., and it is not easily stored. It must be generated as it is consumed, minute-by-minute. Traditionally, dispatchable (mostly fossil) power plants are turned on and off and ramped up or down as necessary to follow changing electric demand in real time. Plants are generally operated in order of lowest incremental cost first, to minimize total cost. Wholesale power consists of several different products, managed and transacted through ISO-NE markets:

- **Energy** is the electricity actually produced and consumed to meet demand (load).
- **Capacity** is the ability to produce energy on demand, typically required to meet peak load.
- **Ancillary services** are necessary to manage power system operations, e.g., very short-term flexibility to match supply and demand.
- **RECs** (renewable energy certificates) represent the renewable attribute of generation, and can be separated from the power itself. One REC represents the renewable attribute of one MWh generated by a renewable resource. RECs are used to track compliance with states' renewable standards, which require that a specified percentage of power must come from renewable sources.

Renewable generation, such as wind and solar, is typically intermittent and cannot be dispatched to follow load. Yet it provides power at essentially no incremental cost once the generation is installed, so its energy is utilized first when it is available. As the grid transitions from a primarily fossil system toward a renewable energy system, there will still be fossil generating capacity that will generate less electricity overall but will be available to generate during periods when there is insufficient clean generation resources to fully meet electricity demand. Most fossil resources will still be in operation in 2030 when Rhode Island reaches its 100% renewable electricity goal, since the other New England states are not currently planning to increase their renewable requirements as quickly as Rhode Island. The available fossil resources will be needed to respond to maintain system reliability, responding to the intermittent operation of renewable energy resources and maintaining the balance between electricity generation and electricity demand at low cost, albeit with the associated GHG emissions.

Beyond 2030, as other New England states' renewable requirements also rise, the entire regional grid will transition to higher levels of renewable energy. Even though fossil capacity may remain for occasional usage to support reliability, the ability to operate this dispatchable generation is likely to be limited by emissions constraints. System operators will thus need additional non-emitting resources to match supply to load in real time, such as energy storage (e.g., batteries) and flexible load on a very large scale, which will increase the costs of providing reliable electricity to customers.

regional system.[10] All the New England states have renewable energy requirements similar to the Rhode Island RES that mandate a specified percentage of the total covered electricity consumption in the state must come from renewable sources. Currently, the 2030 mandates are 25% in Massachusetts and New Hampshire, 40% in Maine (primarily from existing hydro resources), 48% in Connecticut, and 71% in Vermont.[11]

Across New England, the generation of renewable energy and compliance with state-by-state renewable energy standards are tracked through Renewable Energy Credits, or RECs. Each megawatt-hour (equivalent to 1,000 kWh) of energy that a renewable energy resource generates results in one (1) REC. The generation of RECs is centrally tracked through the New England Power Pool Generation Information System (NEPOOL GIS). A qualified renewable energy resource in one New England states can generate RECs that are used to meet the requirements of another state (with some state-to-state variation in what kinds of generation qualify for RECs).[12] Load serving entities must then acquire and submit sufficient RECs to match their obligation, which is determined by the amount of electricity demand they serve and the specific requirement in their state (e.g., 16% in 2020 for Rhode Island).[13] The buying and selling of RECs by renewable energy resources, traders, and obligated entities results in a market price of RECs that is normally quite similar across the New England states. Under a renewable energy requirement like the RES, the renewable energy generation and RECs are tracked at an annual level; it will not necessarily balance in each hour.[14]

Most states with renewable energy requirements, including Rhode Island, also include an option for an alternative compliance payment (ACP) that load serving entities can pay rather than acquire RECs generated by renewable energy resources. The ACP effectively sets a cap on the REC price. Rhode Island's ACP is currently $72/MWh and rises each year with inflation.[15] The ACP effectively sets a cap on the REC price. If REC market prices are near the ACP, load serving entities will be indifferent between paying the ACP and purchasing RECs. Choosing to pay the ACP may not directly or immediately support renewable energy generation, though Rhode Island uses its ACP revenues to fund renewable energy incentives in Rhode Island. On the other hand, if RECs are very inexpensive due to an excess of RECs in the market, purchasing market RECs may not provide additional GHG reductions. That is, these RECs may represent surplus renewable energy (and GHG offsets) beyond the aggregate New England RPS requirements that would have existed whether or not the RECs were purchased. This would violate the Guiding Principle that GHG reductions should be additional and beyond what would occur otherwise.

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[10] There are other shared clean energy policies in New England. For example, all New England states are also members of RGGI, the Regional Greenhouse Gas Initiative that coordinates regional carbon limits in the electricity sector by pricing a limited number of carbon allowances available for larger-emitting power plants.

[11] See: https://www.dsireusa.org/

[12] Renewable energy resources that wish to have their RECs qualified for the Rhode Island RES – whether located in Rhode Island, throughout New England, or in adjacent control areas – must first be certified by the Public Utilities Commission.

[13] National Grid is the only distribution utility in Rhode Island whose load is subject to RES requirements. Pascoag Utility District and the Block Island Utility District are statutorily exempt from the Renewable Energy Standard.

[14] Market mechanisms and technologies that account for the hour-to-hour timing of renewable generation and load will begin to gain importance between now and 2030, but will not yet be critical issues since the system will still contain significant (though decreasing) amounts of fossil generation. They will become critical for reliable operations in the longer term as renewable generation increases to much higher levels across New England, and it becomes more difficult to use fossil energy to balance the system. For example, the Massachusetts Clean Peak Energy Standard is designed to provide incentives to clean energy technologies that can supply electricity or reduce demand during seasonal peak demand periods, which will reduce the residual balancing requirements between load and supply. Storage technologies will also become crucial for short-term balancing.

[15] Rhode Island Public Utilities Commission, Alternative Compliance Payment Rate, accessed December 13, 2020.

II.B Operationalizing the 100% Renewable Goal

Governor Raimondo's Executive Order 20-01 accelerates Rhode Island's transition to a renewable energy portfolio by setting the goal to "meet one hundred percent (100%) of the state's electricity demand with renewable energy resources by 2030." In the context of the New England electricity market discussed above, and consistent with the guiding principle to build on existing renewable energy mechanisms, we define meeting 100% renewable electricity as ensuring that the annual production of renewable energy and associated RECs is sufficient to match all of Rhode Island's annual electricity demand. Specifically, for the purposes of this analysis, we assume that as a component of achieving its 100% goal, Rhode Island will increase the RES to 100% by 2030. Under this new RES requirement, suppliers would need to acquire and retire RECs equal to 100% of their Rhode Island customer load (plus line losses) on an annual basis in 2030 and beyond. Achieving the 100% renewable electricity goal does not require shutting down all fossil generation within Rhode Island. As further explained in the sidebar, it is likely that fossil fuel-based generating resources will continue to operate through the

Does "100% Renewable" require shutting down all fossil generation in Rhode Island?

Achieving 100% renewable electricity does not require shutting down all fossil generation resources in Rhode Island. Executive Order 20-01 challenges Rhode Island to "meet one hundred percent (100%) of the state's electricity demand with renewable energy resources by 2030", which is different from mandating the closure of in-state fossil fuel generators that supply the regional electric grid with electricity. Meeting Rhode Island's entire electricity demand with incremental renewable energy will cause a corresponding reduction in the generation of fossil energy across the regional power system, but does not require shutting down existing non-renewable generators within the state. As described above, Rhode Island is part of the New England electricity system, and depends on the regional system to ensure reliable power at reasonable cost. The regional power system will still rely on fossil fuel-fired generators beyond 2030, though to a declining extent as other New England states also shift toward more renewable energy and less fossil energy. As policies like Rhode Island's 100% renewable electricity goal and other states' rising RPS requirements reduce generation from fossil fuel-fired generators, each of those facilities will determine whether it is economic for them to continue to operate, and will ultimately close if not.

Importantly, however, fossil generating plants can provide services other than just fossil-fired energy. In the long run, the New England system may need dispatchable, fuel-fired generators, like existing gas plants, as backup to ensure reliability for those times when renewable production is less than load. These fuel-fired plants will burn less fossil fuel over time as renewable generators displace the need for their energy, and they may ultimately switch to burning renewable fuels like hydrogen or renewable gas or oil, rather than fossil. Alternatively, it may be that cost effective storage resources will fill the role formerly played by fuel-fired generation, which would then retire. What technologies will ultimately best meet the region's electricity needs remains unclear, but it is not necessary to shut down fuel-fired generators in the near term to reduce the amount of fossil fuel burned, and it may be advantageous to keep them.

end of the decade and beyond to maintain safe and reliable power supply for Rhode Island and New England.

Solely increasing the RES to require suppliers to purchase RECs will not necessarily achieve 100% renewable electricity. An important consideration for developing policies to meet the 100% renewable goal is that the RES obligation and market REC prices provide a short-term incentive for increasing renewable energy generation. In New England this short-term incentive is often insufficient, because attracting new renewable energy resources requires making large, long-term investments. This mismatch between short-term incentives and long-term investment needs means that even very attractive REC prices for the upcoming years may not provide sufficient revenues to support investment and financing of a renewable project with a life of 20 years or more. Thus, to achieve this ambitious, nation-leading goal in a manner that aligns with the Guiding Principle to provide additional GHG reductions at the lowest reasonable cost, Rhode Island will need to match the higher demand for RECs from the 100% RES with programs and procurements that support the development of new renewable energy resources and the RECs they will produce.[16]

Rhode Island currently has a number of existing programs that support new renewable generation. As noted above, these programs include long-term contracting authority granted to National Grid, the Renewable Energy Growth program, the Renewable Energy Fund, and the regulations that support net metering and virtual net metering. These programs generate sufficient RECs to comply with the RES requirement for 2021 and 2022 (17.5% and 19.0%, respectively). In fact with the addition of the 400 MW Revolution Wind project in 2024, the Rhode Island programs support renewable energy resources that will go well beyond the near-term RES requirement, covering about 40% of current electricity demand. Continuation and potential expansion of these programs, as well as additional procurements, present a path forward to help fill the gap to reach Rhode Island's 100% goal with verifiable, additional renewable electricity resources.

II.C Establishing the Gap to 100% Renewable Electricity by 2030

To identify the renewable electricity gap to achieve 100% in 2030, we first examined expected 2030 electricity demand in Rhode Island, and then projected the amount of renewable electricity generation in 2030 from resources already online or committed through Rhode Island's programs and procurements (excluding future resources that might result from continuation of existing programs).

Beginning with electricity demand, **FIGURE 2** shows Rhode Island projected electricity demand for 2020 to 2030 for three cases: Base Load Case, High Load Case, and a Low Load Case. Each case is based primarily on National Grid's 2019 electricity demand forecast, with adjustments to electrification and energy efficiency assumptions for the High and Low Load Cases. National Grid forecasts that conventional electricity demand (i.e., current uses for electricity) initially decreases, due largely to organic and programmatic energy efficiency. As efficiency opportunities become saturated, conventional load levels off and rises slightly. Electrification demand is very limited in the next several years but grows more significantly closer to 2030, such that total electricity demand begins to rise in the latter half of the coming decade to 7,700 GWh in 2030.

The Base Load Case assumes additional electrification-related demand by 2030, including 5% light-duty-vehicle electrification (dark blue), a similar share of medium- and

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[16] New renewable generation may not be additional in every circumstance – e.g., if it forces curtailment of other renewables and thus does not offset fossil generation. This situation is currently rare in most of New England, though could become more common in the future as renewable penetration gets high and curtailments increase.

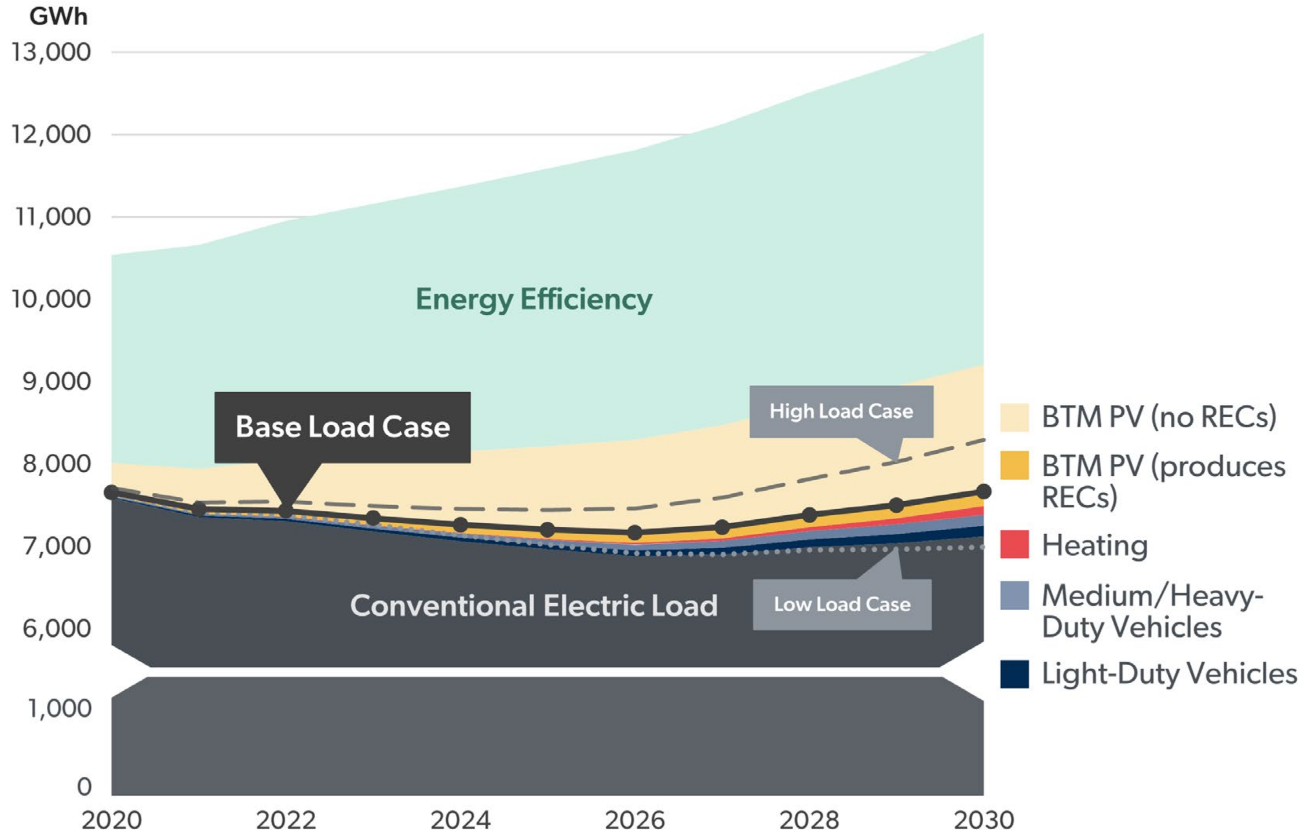

FIGURE 2: PROJECTED RHODE ISLAND ELECTRICITY DEMAND (2020–2030)

Note: "BTM PV" is Behind-the-Meter solar photovoltaic generation

heavy-duty-vehicle electrification, and 5% additional heating electrification (red).[17] The High Load Case assumes a higher penetration of electrified transportation and heating (15% light-duty vehicle electrification and 10% additional heating electrification by 2030). The Low Load Case assumes the same electrification as the Base Case but with greater additional energy efficiency measures to maintain 180 GWh/year efficiency savings through 2030. Although electrification load is expected to be modest by 2030, it will likely accelerate later in the 2030s and 2040s, as electric vehicles and heat pumps become more widely available and achieve substantial cumulative uptake.

The Base Load Case assumes additional electrification-related demand by 2030, including 5% light-duty-vehicle electrification (dark blue) and 5% additional heating electrification (red). The High Load Case assumes a higher penetration of electrified transportation and heating (15% light-duty vehicle electrification and 10% additional heating electrification by 2030). The Low Load Case assumes the same electrification as the Base Case but with greater additional energy efficiency measures to maintain 180 GWh/year efficiency savings through 2030. Although electrification load is expected to be modest by 2030, it will likely accelerate later in the 2030s and 2040s, as electric vehicles and heat pumps become more widely available and achieve substantial cumulative uptake.

To incorporate this load projection into understanding the renewable electricity gap to reach 100%, **FIGURE 3** illustrates Rhode Island's existing renewable generation in the green and blue bars. The state currently supports about 850

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[17] This load projection is adjusted to include load that is served by behind-the-meter generation (such as rooftop solar) that earns RECs, to prevent double-counting the renewable attributes of such generation.

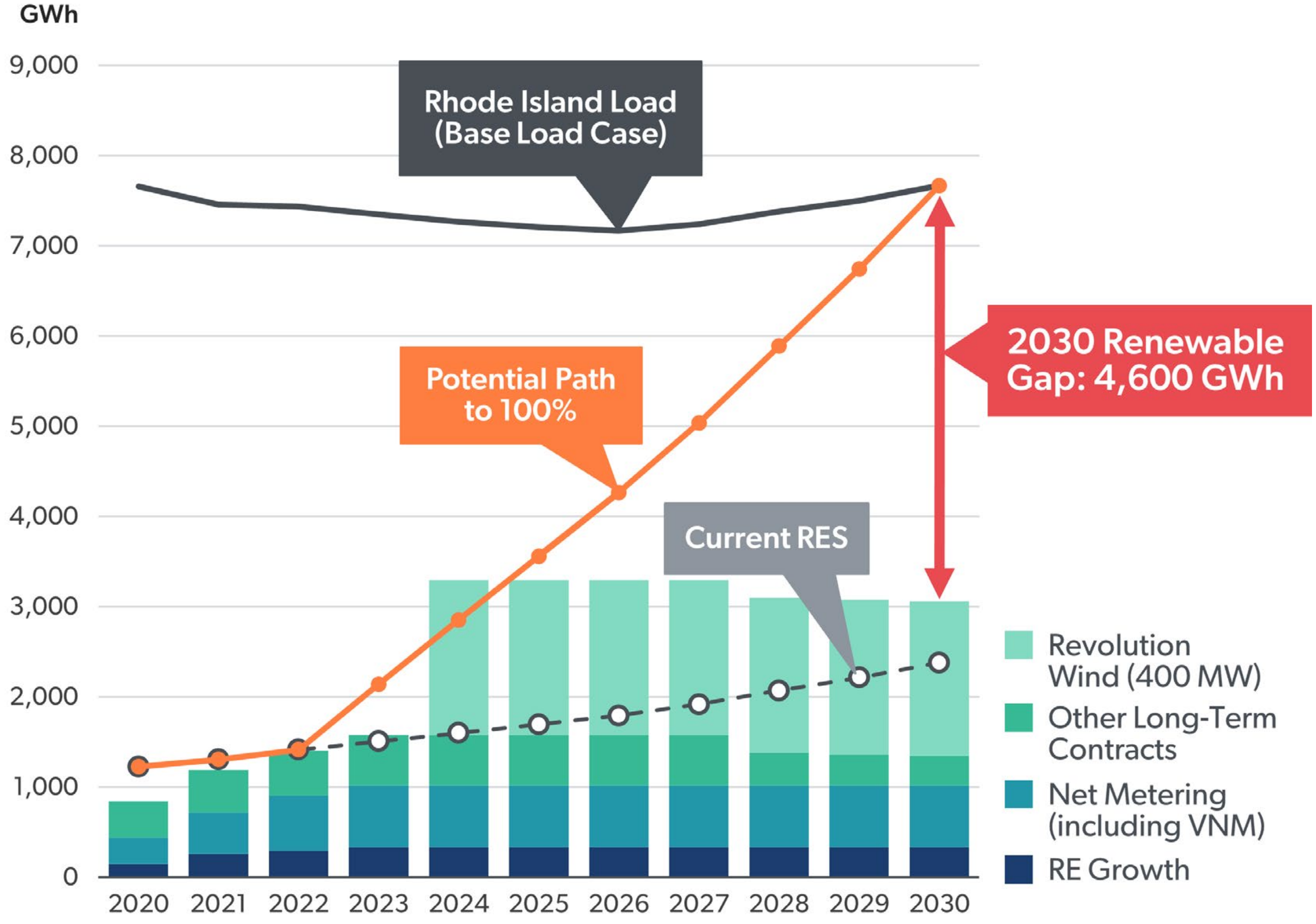

FIGURE 3: RENEWABLE ELECTRICITY GAP TO ACHIEVE 100% RENEWABLES

GWh of renewable energy in 2020, and has already made commitments that increase to 3,300 GWh by 2024. Most notably, the Revolution Wind offshore wind project, of which Rhode Island has contracted for 400 MW, is expected to come online in 2024 and will generate about 1,720 GWh of electricity annually – more than half of the existing portfolio. The total then declines slowly as some existing renewable energy contracts expire by 2030.

The orange line on Figure 3 projects a potential path for the RES, beginning at the existing RES and reaching 100% in 2030. A different trajectory is possible, as long as it reaches 100% by 2030. As shown, the difference between 2030 projected electricity demand of 7,670 GWh and the 3,060 GWh of existing and committed renewable generation leaves a 2030 renewable energy gap of 4,600 GWh. This is about 60% of 2030 electricity demand, and defines the amount of additional new renewable electricity that Rhode Island must secure by 2030 to reach its goal, beyond current commitments.[18]

The quantity of incremental renewable energy generation needed to meet the 2030 goal of 100% renewable electricity is uncertain. The 2030 renewable energy gap illustrated above,

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[18] The calculation of the 2030 renewable energy gap does not depend on how the hourly and seasonal timing of renewable energy generation compares with the timing of electricity demand, since the structure of the RES requires only that renewable energy generation and the associated RECs match the required percentage of total electricity demand on an annual basis. However, the analyses in later sections do consider hourly generation and load patterns, which are important for understanding ratepayer costs and risks, and for considering how load and generation shapes match, which will become more important farther in the future.

4,600 GWh, is our base estimate; the actual size of the gap will depend on future demand growth. A number of factors influence conventional load growth and create uncertainty in load projections; these include economic growth, organic and programmatic energy efficiency improvements, and year-to-year weather variability. Additional electricity demand uncertainties include the pace of transportation and heating electrification, and long-term temperature trends due to climate change.

Similarly, the amount of renewable energy generation that will be successfully acquired by planned programs and solicitations is uncertain due to the timing with which new resources will come online, and even the amount of energy generated based on how much the sun shines or the wind blows in that particular year. Historically, renewable energy resource potential in New England has differed year-by-year by up to 7% of the long-term annual average for solar resources and 11% for wind resources.[19]

Each of these factors can be projected, but not with perfect accuracy. Projections can and will be updated over time – by 2027, estimates of likely 2030 load will be less uncertain than today's estimate – and the gap can be similarly updated. This uncertainty requires that policy mechanisms to achieve 100% renewable electricity maintain some flexibility regarding quantity. In the end, there will be some unavoidable residual mismatch between the total renewable energy generation and electricity demand in 2030, but the difference can be bridged by buying or selling RECs to match the RES requirement, and/or by banking RECs over time.

Some of this renewable electricity gap may be filled by continuation of existing renewable energy programs to acquire more new resources. If existing programs continue at roughly their projected pace from now until 2030, including 40 MW per year of retail solar through the Renewable Energy Growth program and 80 MW per year of net metered solar, add an incremental 1,500 GWh by 2030.[20] Of course, these current programs could be expanded, allowed to shrink, or reach the maximum allowed capacity (such as for VNM capacity) so that they fill a larger or smaller portion of the gap, as desired.

In addition to existing programs, Rhode Island recently announced its intent to solicit proposals for up to 600 MW of additional offshore wind resources.[21] A draft Request for Proposals is anticipated to be filed for regulatory review in early-2021. If the procurement is authorized and the full 600 MW is ultimately acquired, the new offshore wind resource would add about 2,700 GWh per year, or about 35% of 2030 electricity demand, filling the majority of the renewable energy gap. In combination, the potential future development of retail solar through existing programs and 600 MW of offshore wind through the pending solicitation could add 4,200 GWh per year, leaving a remaining gap of just 400 GWh per year of renewable electricity.

Procuring additional renewable energy resources from new or expanded programs, or possibly from purchasing RECs from the market are potential approaches to reaching 100%. These questions regarding the mix of resources that may be attractive for achieving 100% are the subject of the next several sections.

II.D Maintaining 100% Renewable Electricity Beyond 2030

The primary focus of this report is on achieving the 100% renewable electricity goal by 2030. But it is also important to consider implications of maintaining this level in the years beyond 2030. Two of the most significant factors for Rhode

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[19] The average annual resource potential in ISO-NE has ranged from 93% to 107% of the long-term average from 2015 to 2019 for solar and from 89% to 107% of the long-term average from 2008 to 2019 for wind. Mark Bolinger, et al., Utility-Scale Solar Data Update: 2020 Edition, November 2020, p. 25; Ryan Wiser, et al., Wind Energy Technology Data Update: 2020 Edition, August 2020, p. 50.

[20] Projected growth of net metered solar is based on National Grid's forecast through 2023 and then maintaining the 2023 new capacity of 64 MW through 2030.

[21] See https://www.ri.gov/press/view/39674

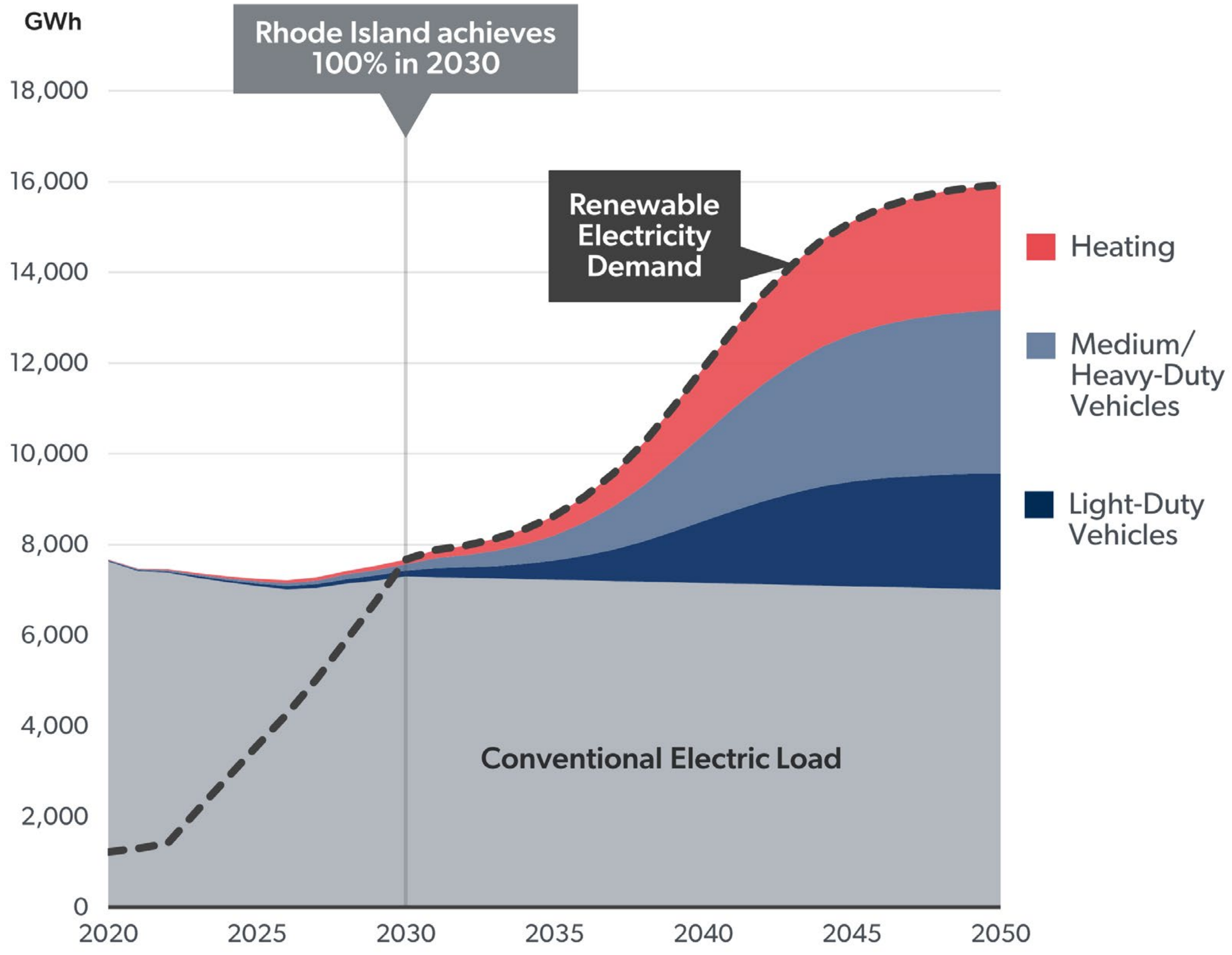

FIGURE 4: POTENTIAL RHODE ISLAND ELECTRICITY DEMAND PROJECTION TO 2050

Island to consider in the years beyond 2030 are the likely large increase in electricity demand due to electrification, and the increasing share of renewable energy resources across the New England system.

Electricity demand is likely to grow significantly after 2030 due to electrification of transportation and space heating.[22] To remain at 100% renewable electricity in the longer term, Rhode Island will need to continue adding considerable amounts of new renewable generation to its portfolio beyond 2030. **FIGURE 4** shows a potential projection of Rhode Island electricity demand out to 2050 in which electrifying significant portions of the transportation and heating sectors could cause the state's total electricity demand to double between 2030 and 2050. If this pace of electrification materializes, Rhode Island would need to continue adding up to 400 – 500 GWh per year of new renewables beyond 2030, which is roughly similar to the pace up to 2030. In this longer-term view, achieving 100% renewable electricity by 2030 is more of a milestone along the way to decarbonizing the broader economy, rather than the fulfillment of a significant goal for just the electricity sector.

Another implication of this longer-term increase in electricity

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[22] The long-term demand projection assumes heating decarbonization primarily occurs through adoption of electric air-source and ground-source heat pumps. As discussed in the Heating Sector Transformation report, other decarbonization pathways include renewable fuels such as renewable hydrogen, natural gas, or diesel fuel. Dean Murphy and Jurgen Weiss, Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050, Prepared for the Rhode Island Office of Energy Resources and Division of Public Utilities & Carriers, April 22, 2020.

demand is that the mix of renewable energy technologies in Rhode Island's portfolio by 2030 need not stay the same thereafter. Continuing to add renewable energy resources will also create ongoing opportunities for Rhode Island to rebalance the state's renewable energy portfolio beyond 2030 in response to changes in resource availability and costs, and changes in the generation mix of the broader region. By the 2040s, many of the renewable energy resources Rhode Island had first acquired may be nearing the end of their economic life and could need replacement. In this way, renewable energy development in Rhode Island will continue for the foreseeable future, requiring continued investment and reinvestment to meet the energy demands of the state and the wider New England region.

Beyond 2030, the regional power system will also continue to evolve towards greater penetration of renewable energy resources, driven by other states' policies and the declining costs of renewable energy resources. The increased reliance on renewable energy resources will increase the importance of short-term balancing issues, where a supply mix that contains a higher share of intermittent resources must still be matched with demand minute-by-minute. Longer-term, seasonal energy balancing issues are likely to become more important and the structure of wholesale electricity markets and products may change (different definitions of capacity, ancillary services, storage products serving varying timeframes, etc.). The challenges and potentially the costs associated with addressing these issues may rise. The lowest cost approaches to balancing the system are highly uncertain given the potential for changing needs and technological advances over this long timeframe.

Most of these challenges are unlikely to be major issues by 2030, though they will be emerging by then and will become increasingly important beyond 2030. This trend is apparent, for example, in the market simulation results, described in more detail in the Technical Support Document, that show that the amount of economic 2-hour and 4-hour battery storage increases from 1,300 MW in 2030 to 19,600 MW in 2040. Additional new technologies will likely be necessary in the 2040 to 2050 timeframe for longer-term balancing, such as thermal generators fueled by renewable natural gas or renewable hydrogen.

As other New England states ramp up their clean energy goals, the manifestation of these issues could accelerate. Rhode Island will need to coordinate with other New England states and electricity market stakeholders to consider these factors in earnest.

III. Analyzing Rhode Island's Options for Achieving the 100% Renewable Electricity Goal

Rhode Island has access to several types of renewable energy generation resources to fill the gap and achieve 100% renewable electricity by 2030. In this section, we identify the primary candidate resources that can fill a significant portion of the gap, and analyze their costs, market value, and production profiles.

For each of the candidate resources, we create a hypothetical Technology Bookend corresponding to filling the entire renewable energy gap with that one renewable resource type. Reflecting the directives of Executive Order 20-01, we evaluate these Bookends based on two primary metrics to enable comparisons across the technologies. The first metric is their "above-market cost" to ratepayers – the amount by which the costs of these renewable resources exceeds the market cost of comparable (non-renewable) energy products. The second metric is the local economic development impacts, measured in terms of GDP and employment impacts. Later in this section, we look at several portfolios consisting of combinations of the resource types using the same metrics to identify tradeoffs.

III.A Candidate Renewable Energy Resources

We first review the availability of candidate resources, screening for resources that may be able to fill a substantial portion of the 4,600 GWh renewable energy gap. The primary candidate renewable energy resources are:

- Offshore wind, primarily off the coast of Rhode Island;
- Land-based wind, primarily available in northern New England and New York;
- Solar photovoltaic (PV) connected to the high-voltage transmission system in Rhode Island and across New England ("wholesale solar"); and,
- Solar PV connected to the lower-voltage distribution system within Rhode Island ("retail solar").

Taking account of the varying generation profiles of these resources, **FIGURE 5** shows the capacity of each resource type needed to close the 4,600 GWh renewable energy gap identified in the previous section to meet the 2030 goal.[23] The figure shows that filling the renewable energy gap would require 2,700 MW to 4,300 MW of solar capacity, compared with 900 MW to 1,700 MW of wind, since each megawatt of solar

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[23] Different resources produce different amounts of energy over the course of a year, relative to their maximum generating capacity. The "capacity factor" of a resource is expressed as a percentage, relating how much energy it produces in a year as a fraction of its maximum theoretical output, if it operated at full capacity for all 8,760 hours in a year. Typical capacity factors in New England are 36% for land-based wind, 52% for offshore wind, 16% for wholesale solar, and 14% for retail solar.

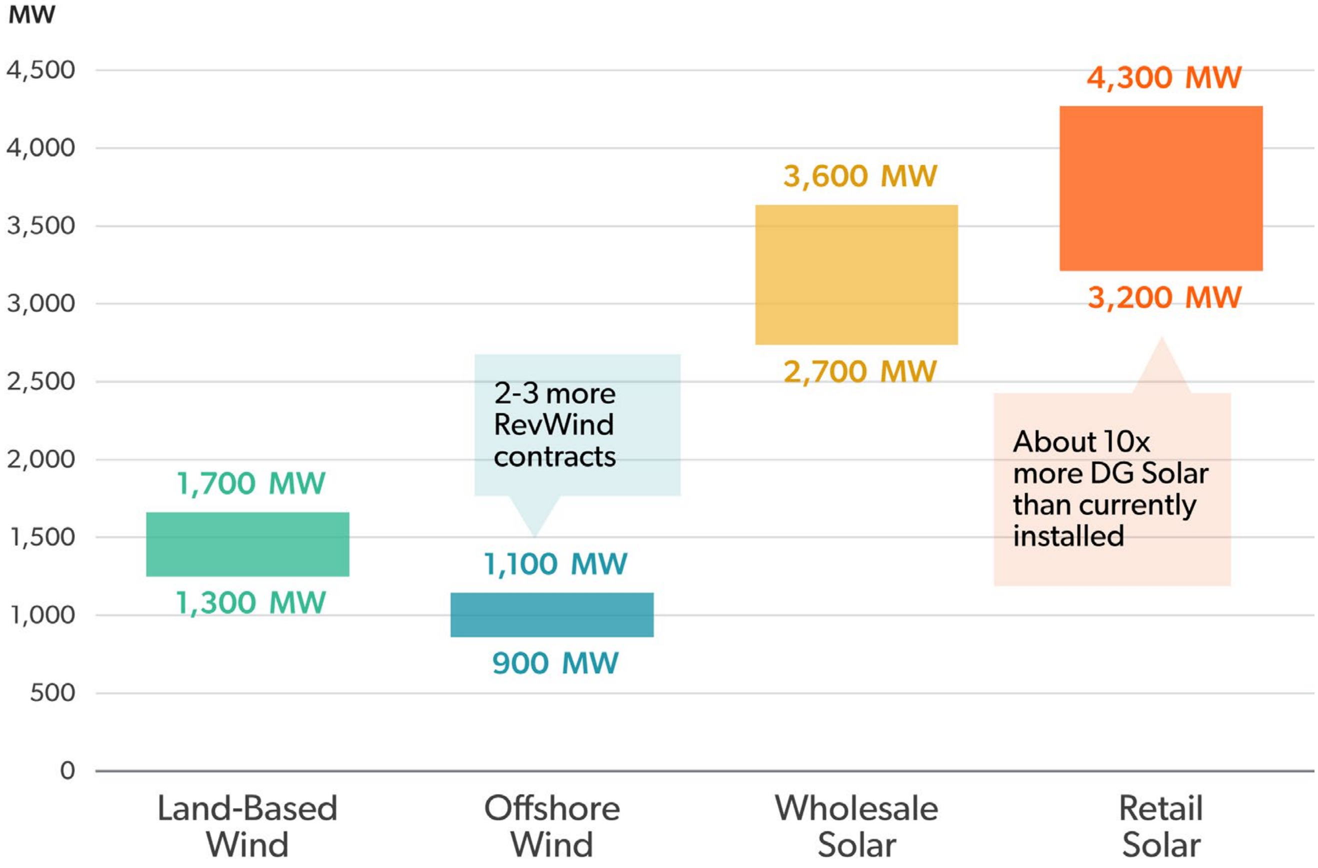

FIGURE 5: CAPACITY OF EACH TECHNOLOGY NEEDED TO FILL 2030 RENEWABLE ENERGY GAP

generating capacity produces less total energy over the year than a megawatt of wind.

Next we consider the availability of these resource types, the costs of developing them (including both the cost of the renewable generation itself and the power system upgrades necessary to deliver the power to customers), and the value of those resources in the New England electricity market (including energy, capacity, and RECs). These cost and value measures are used to estimate their resulting impact on ratepayer costs. We then examine the impact that each resource type will have on Rhode Island's economy, including GDP and employment.

Resource Availability

The first step to understanding how to achieve 100% renewable electricity by 2030 is identifying the availability of each of the candidate renewable energy resources and the potential for each resource to contribute to closing the gap.

Offshore Wind Resources: The first operational large-scale offshore wind facility in the U.S., Block Island Wind Farm, started operating in 2016 off the Rhode Island coast. Since then, New England states have signed contracts for 3,100 MW of offshore wind resources, including the 704 MW Revolution Wind Farm contracted jointly by Rhode Island (400 MW) and Connecticut (304 MW) utilities in 2018.[24] As noted above, National Grid recently initiated a new solicitation for up to 600 MW of additional offshore wind on behalf of its Rhode Island customers. In addition, Massachusetts and Connecticut target an additional 2,800 MW of offshore wind resources by 2035. In total, the New England states are targeting over 6,000 MW of offshore wind resources in the next decade or

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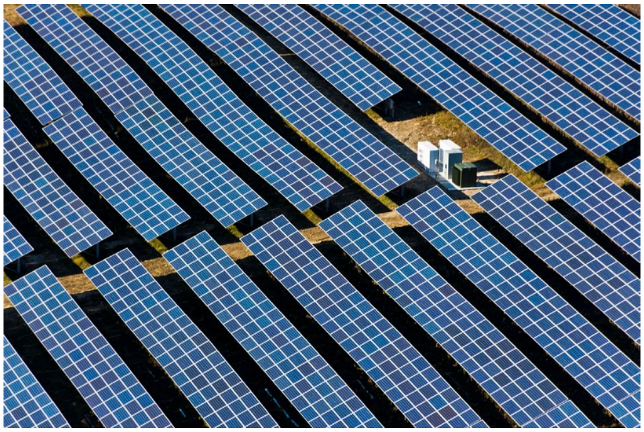
[24] See the Technical Support Document for a summary of completed and announced offshore wind procurements.

Land-Based Wind

Offshore Wind



Wholesale Solar

Retail Solar

so. However, the first offshore wind farm selected during the recent procurements, Vineyard Wind by Massachusetts, is not currently scheduled to begin operations until 2023 and has faced challenges obtaining all of the permits necessary to begin construction.[25]

Offshore wind facilities are located in federal waters that require leases from the U.S. Bureau of Ocean Energy Management (BOEM). BOEM currently has identified leases for future development that can support 15,000 MW of offshore wind resources, and developers have indicated their interest in developing additional offshore wind capacity.[26] As of August 2020, developers submitted proposals for over 12,000 MW of offshore wind facilities for evaluation by ISO-NE to determine the need for and cost of system upgrades to connect the new facilities to the New England grid.[27]

As we discuss in more detail below, adding this scale of offshore wind facilities to serve the New England market will require identifying and developing additional interconnection points with the onshore system, and expansions and upgrades to the existing network. As the most accessible and lowest cost interconnection points are utilized by early projects, the costs of interconnecting still more offshore

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[25] See, e.g., Jennifer A Dlouhy and Will Wade, Vineyard Wind Is Said to Face Lengthy Delay After Pulling Permit, Bloomberg, December 11, 2020; Bureau of Ocean Energy Management, Cape Wind, accessed December 13, 2020.

[26] Pfeifenberger, et al., Offshore Transmission in New England: The Benefits of a Better Planned Grid, Prepared for Anbaric, May 2020, p. 11.

[27] The ISO-NE interconnection queue is available here: https://irtt.iso-ne.com/reports/external

Other Renewable Energy Technologies

Other resource types may enter the market to help Rhode Island fill the gap. However, these resources are likely to play a smaller role in the state's clean energy future than the four primary technologies identified, and were not included in the analytic evaluations here. To the extent they may be available, some of these other options may offer attractive, if limited, opportunities. In the longer term, technological progress could change the technological and/or economic potential of these options.

- **Landfill Gas and Biogas:** Methane is produced by the anaerobic decay of organic matter, such as occurs naturally in landfills, and in a controlled environment in a biogas digester from animal or food waste. This methane can be captured and used as fuel to generate electricity. While Rhode Island currently contracts for 32 MW landfill gas and 3 MW of Digester Gas, it has not received any recent proposals for these technologies, to our knowledge, and no similar capacity is being developed.
- **Other Eligible Biomass:** Biomass, such as excess foresting material, agriculture waste, and wood pellets, can be burned to produce heat and steam to turn an electric generator. Such facilities are primarily located in northern New England near convenient sources of biomass. Currently, there is no new biomass capacity being developed in New England.
- **Solar Thermal:** Solar thermal generation concentrates sunlight with mirrors to reach very high temperatures, creating steam to turn a generator. Incident sunlight in New England is insufficient to make current solar thermal technologies practical.
- **Small (<30 MW) hydro:** Hydroelectric generators use moving water (such as water flowing through a dam on a river) to turn an electric generator, and smaller hydro facilities are often classified as renewable generation. Rhode Island allows for limited eligibility of existing small hydro under the current RES structure, but opportunities for new small hydro are quite limited in New England.
- **Tidal hydro:** Tidal hydro works on the same principle as a dam, but uses the motion of tidal currents rather than a river. This and other experimental hydro technologies are not currently commercially viable.
- **Fuel cells:** Fuel cells convert fuel to electricity directly through a chemical process similar to a battery, rather than burning it. There is limited fuel cell development in New England, with just 25 MW in the ISO-NE queue in Connecticut. Available fuel cells use natural gas as fuel, which does not qualify as renewable in Rhode Island; hydrogen fuel cells are not currently commercially viable for power generation.
- **Nuclear:** Nuclear energy is not considered a renewable resource in Rhode Island or most other states, despite its lack of emissions, and is controversial for a number of reasons. Further, it is extremely unlikely that new nuclear generation could be developed by 2030.
- **Geothermal:** Geothermal electricity generation uses the heat deep inside the earth to create steam to drive a turbine. The availability of geothermal is highly dependent on local geology; with available technologies, New England's geology is not suitable.

wind are expected to increase.[28] In addition, the delays faced by the already-procured offshore wind resources may increase future development costs, require facilities to be built under accelerated timeframes, and delay developers from improving their projection of the costs and timeline of completing future projects.

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[28] Pfeifenberger, et al., Offshore Transmission in New England: The Benefits of a Better Planned Grid, Prepared for Anbaric, May 2020

Land-Based Wind Resources: Currently, nearly all 1,400 MW of wind generation capacity in New England is from land-based wind resources.[29] However, development of large-scale, land-based wind resources has been limited in recent years. For example, the proposed 250 MW Number Nine Wind Farm in Maine received a contract for its output from Connecticut in 2013 that was later cancelle.[30] The most recently built land-based wind farm is the 29 MW Antrim Wind Farm in New Hampshire that began operation in 2019, after being selected for a contract through the three-state Clean Energy RFP process.[31] Notably, Maine recently conducted a solicitation for renewable resources and only selected a single 20 MW land-based wind project while procuring nearly 500 MW of solar resources.[32]

The challenges of accessing the high-quality wind resources in northern New England has limited development of land-based wind in the region. ISO-NE completed several planning studies over the past decade to identify transmission system upgrades to increase access to land-based wind resources; these have identified several projects, though they are costly as explained further below.[33] Despite these hurdles, land-based wind resources continue to be pursued with about 2,000 MW of resources in Maine in the ISO-NE interconnection queue.

In addition to 19 MW of small-scale wind capacity in Rhode Island through the Renewable Energy Growth program, Rhode Island has recently contracted for the output of the 126 MW Cassadaga and 80 MW Copenhagen wind farms located in New York. The New York State Energy Research and Development Authority (NYSERDA) has procured nearly 1,000 MW of wind capacity through their 2017 to 2019 REC procurements,[34] but are likely to face growing transmission system upgrades necessary for continued development.[35] An additional 4,000 MW of wind in New York is currently being studied through the interconnection process.[36]

With the lack of recent large-scale resources developed in New England and significant demand for renewables in New York, the potential for land-based wind to meet a significant portion of Rhode Island's renewable energy gap is likely to be limited without significant transmission system upgrades on the New England and perhaps the New York systems. However, the recent contracts signed for over 200 MW of capacity suggest that some modest additional amount may be available, and so we include land-based wind as a candidate resource for consideration.

Wholesale Solar Resources: Wholesale solar refers to large-scale solar photovoltaic generation facilities connected directly to the high-voltage transmission system, where the power is transacted in wholesale markets. It has grown steadily in New England, with about 1,700 MW installed in 2020 and another 1,700 MW projected by ISO-NE to be added by 2029.[37] Rhode Island has signed contracts for the output of 71 MW of solar resources through its Long-Term Contracts (LTC) program since 2018, including 5 MW from the Hope Farm Solar located within the state. Most recently, Rhode Island contracted for 50 MW from the 120 MW Gravel Pit Solar project located in Connecticut.

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[29] ISO-NE, Resource Mix, accessed December 21, 2020.

[30] Anthony Brino, Despite energy deal loss, huge wind farm is still on track in Aroostook, Bangor Daily News, September 19, 2016.

[31] Ethan Howland, Three New England states move on 460 MW of renewables, S&P Global Platts, October 26, 2016.

[32] Maine Public Utilities Commission, 2020 Request for Proposals for the Sale of Energy or Renewable Energy Credits from Qualifying Renewable Resources, September 22, 2020.

[33] ISO-NE estimates that a $780 million upgrade would be necessary to access 518 MW of land-based wind in Maine. ISO-NE, Second Maine Resource Integration Study: Results, November 2019.

[34] NYSERDA, Solicitations for Large-Scale Renewables, accessed December 14, 2020.

[35] NYISO, 2019 CARIS Report: Congestion Assessment and Resource Integration Study, July 2020, pp. 84-90.

[36] The NYISO interconnection queue is available here: https://www.nyiso.com/interconnections

[37] ISO-NE, Final 2020 PV Forecast, April 29, 2020, p. 50.

The Solar Siting Opportunities for Rhode Island report identified the technical potential to build 2,540 MW to 6,500 MW of solar on landfills, gravel pits, brownfields, commercial/industrial parcels, and carports in Rhode Island, although it is unclear how many of these sites could support larger-scale, wholesale-level resources or are near to high-voltage transmission infrastructure.[38] Currently, the ISO-NE interconnection queue includes 450 MW of solar resources listed in Rhode Island, all of which have entered since 2018. Out-of-state development of large-scale solar resources has increased considerably in recent years; new solar resources have increased from 340 MW in 2018 to 1,410 MW in 2019 and 3,270 MW in 2020 in the ISO-NE interconnection queue.

Retail Solar Resources: The majority of solar resources across New England (2,300 MW) are behind-the-meter or distributed solar resources that are connected at the distribution system level (rather than being connected to the high-voltage transmission system). ISO-NE forecasts that an additional 2,100 MW of Retail Solar will be added through 2029.[39] Rhode Island has recently added over 300 MW through its Renewable Energy Growth program and its net metering programs. National Grid forecasts an additional 480 MW will be developed in the next three years, primarily through virtual net metering.[40]

Retail solar resources vary greatly in scale, from small residential rooftop facilities of less than 10 kW to large-scale virtual net metering facilities of 5 to 10 MW. The recent Rhode Island solar siting study found that the technical potential for small-scale residential rooftop solar in Rhode Island is 540 MW, though the economic potential is likely only 110 – 260 MW.[41] The study estimated much higher technical potential at ground-mounted sites that can accommodate a larger facility. However, both available land and existing electrical infrastructure are necessary for developing low cost resources, and the study notes that the technical potential for such sites is likely limited by the capacity of the existing National Grid distribution system.[42] National Grid's analysis of the available "hosting capacity" of the existing distribution for new retail solar resources confirms that is the case for a large portion of the state with available land, especially in western Rhode Island where the most solar has been built to date.[43] As further discussed below, the costs of interconnecting solar facilities to the National Grid system have increased recently and are likely to remain high unless there is a coordinated distribution system buildout in anticipation of growing distributed solar and other grid demands.

Resources of several types are available: Overall, there is significant renewable energy resource capacity available within Rhode Island, in other New England states, and in adjacent federal waters to meet Rhode Island's 100% goal. However, all of the candidate resources will require upgrades to the transmission and/or distribution systems for continued growth. Rhode Island should consider approaches to planning and investing in the necessary local distribution and regional transmission infrastructure to reach 100% cost effectively.

Resource Acquisition Costs

The costs of acquiring wind and solar generation resources of all types have declined dramatically over the past several years. However, there are several considerations to weigh for whether similar trends will continue for each of the candidate resources, including the improved economies of scale as renewable energy technologies expand, the experience gained in developing and building resources globally and

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[38] Pat Knight, et al., Solar Siting Opportunities for Rhode Island,Prepared for Rhode Island Office of Energy Resources, August 18, 2020, p. 4.

[39] ISO-NE, Final 2020 PV Forecast, April 29, 2020, p. 50.

[40] Based on historical data and forecasts provided by National Grid on July 15, 2020.

[41] Pat Knight, et al., Solar Siting Opportunities for Rhode Island, Prepared for Rhode Island Office of Energy Resources, August 18, 2020, p. 4.

[42] Ibid, pp. 54-60.

[43] National Grid, Rhode Island Hosting Capacity, accessed on December 14, 2020.

in New England, the phase-out of federal tax credits, site availability, and future system upgrades costs.

We developed cost projections through 2030 for each of the candidate resources, grounded in the most recent publicly-available market data for renewable energy resources that have been acquired across New England, with additional input from renewable developers. We reviewed the contract prices and program costs for acquiring resources, including the long-term contracts recently signed by Rhode Island and other states for offshore wind, and contract prices for distributed solar resources through Rhode Island's Renewable Energy Growth program. Because the structure of payments to developers varies across contracts, we adjusted the contract prices to put them on a common basis, accounting for differences such as contract life, price escalation, online year, and the federal tax credit phase-out. This provides a set of consistent reference points for the current cost of each of the renewable energy resources in New England.[44] The resource acquisition costs are expressed in terms of energy cost (on a dollar-per-MWh basis) so that they are directly comparable.[45]

We then applied cost decline projections from the National Renewable Energy Laboratory (NREL) 2020 Annual Technology Baseline study, characterizing how long-term technology costs may evolve over time, and calibrating NREL's "Moderate" case to the recent New England reference points.[46] NREL also develops a high-cost "Conservative" case and a low-cost "Aggressive" case, which we use to develop a reasonable uncertainty band around future resource costs. Because the NREL cost projections do not account for changes in the costs of transmission and/or distribution system upgrades, we estimated a range of potential future system upgrade costs for each resource, based on existing projects and observed recent trends in interconnection costs, the outlook for future system upgrade needs, and feedback from renewable developers and stakeholders. More details on the reference points and development of the cost projections are available in the accompanying Technical Support Document.

FIGURE 6 shows the resulting cost projections for land-based wind, offshore wind, wholesale solar, and retail solar resources through 2030. The wide ranges of future costs for each resource reflect the uncertainty in future resource costs, which is supported by feedback from renewable developers, the variation in costs seen in recently procured resources, and the potential range of system upgrades necessary to interconnect these resources. shows the resulting cost projections for offshore wind, land-based wind, wholesale solar, and retail solar resources through 2030. The wide range of future costs for each resource reflect the uncertainty in future resource costs, which is supported by feedback from renewable developers, the variation in costs seen in recently procured resources, and the potential range of system upgrades necessary to interconnect these resources.

Below, we describe the primary drivers of the cost projections for each resource type. Additional detail on the derivation of the costs is provided in the Technical Support Document.

- **Offshore Wind:** The four offshore wind projects procured in New England to date have signed contracts for $58–98/MWh for their energy generation and RECs. To project the long-term costs of offshore wind, we adjusted these values for the phase-out of the PTC, differences in price escalation rates across the contracts, and increasing system upgrades

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[44] All costs were standardized to a 20-year contract with prices that escalate with inflation. Our analysis follows existing tax law, under which the federal production tax credit (PTC) for wind resources expires before new wind projects would come online, and the investment tax credit (ITC) for solar resources declines to 10%. As this report is going to press, the U.S. Congress is considering legislation to extend these tax credits at existing levels for several more years. If the credits are in fact maintained at levels above those assumed in our analysis, the incremental cost of renewable resources to Rhode Island ratepayers would be lower.

[45] Throughout this report, unless otherwise specified, monetary values are expressed in real, inflation-adjusted 2020 dollars.

[46] NREL, Electricity Annual Technology Baseline Data Download, accessed on December 14, 2020.

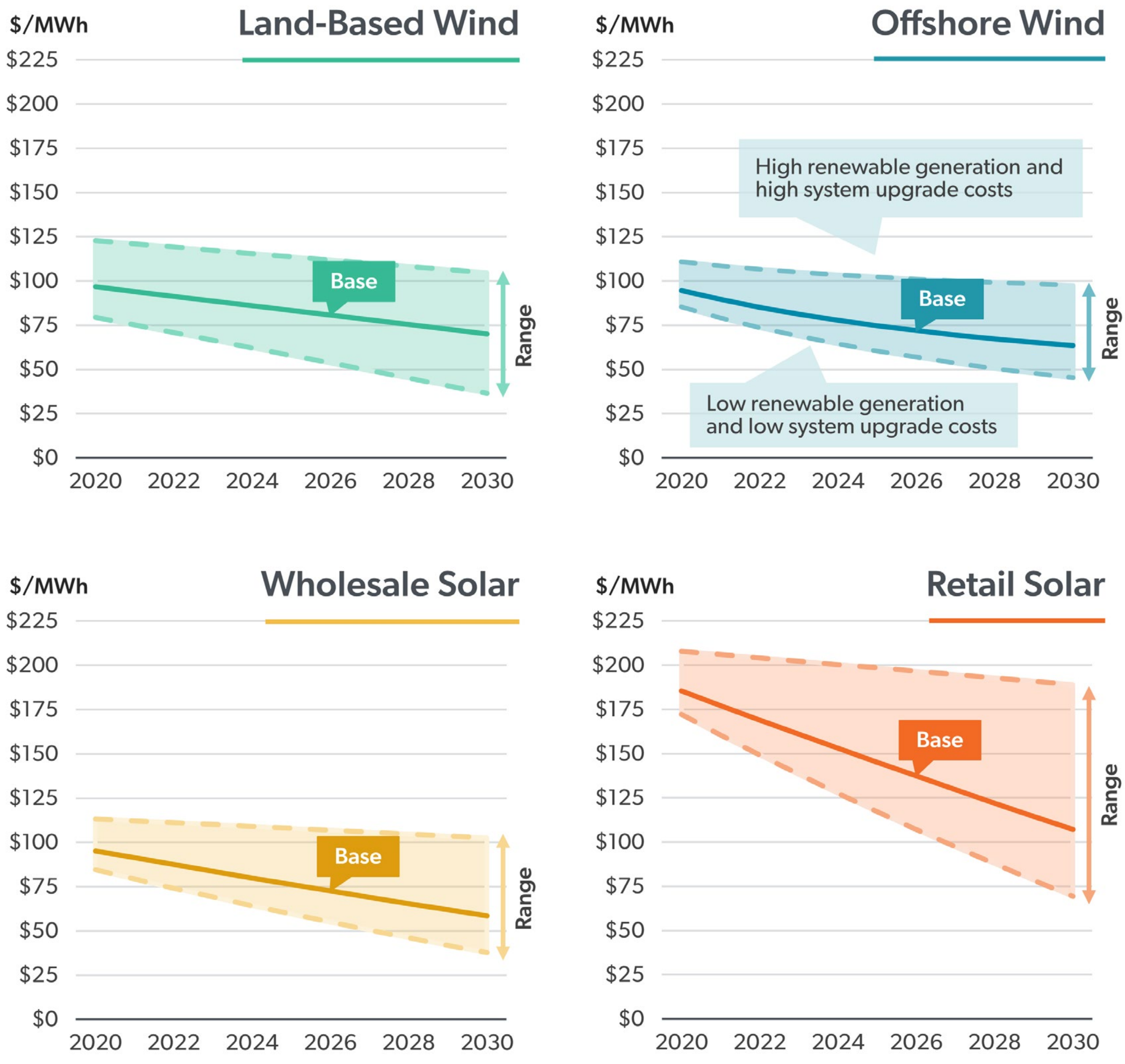

FIGURE 6: PROJECTED RESOURCE ACQUISITION COSTS THROUGH 2030

costs.[47] NREL forecasts cost declines for offshore wind of 1.5% (real) per year at the low end and 6.1% per year at the high end. The net impact of these adjustments result in 2030 offshore wind costs ranging from $45/MWh to $98/MWh, with a Base Case cost of $64/MWh. Costs may end up toward the higher end of this range if the installed costs for offshore wind are higher than is reflected in the contracts for early projects, and if additional offshore wind

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[47] We estimated that the PTC reduced the costs of the offshore wind resources by $11/MWh to $17/MWh based on the expected online dates at the time of the contracts and the PTC phase-out schedule.The contract for Revolution Wind included prices that remained fixed in nominal terms, while the other contracts escalated prices over the contract life. We estimated that offshore wind interconnection and system upgrade costs will increase by $10/MWh to $15/MWh as most easily accessible landing spots and available onshore transfer capacity are filled up by the initial wave of offshore wind resources.

resources involve higher system upgrade costs once the most attractive landing points have been utilized. Costs may end up near the lower end of this range if an expanding industry results in greater economies of scale and more efficient development and construction of offshore wind farms, and if future system upgrade costs are similar to what is reflected in existing contracts.

- **Land-Based Wind:** Rhode Island recently signed contracts for New York land-based wind at around $90/MWh. Similar to offshore wind, the phase-out of the PTC and increased system upgrade costs may tend to increase the costs of new land-based wind, while continued improvement in turbine performance, especially at low wind speeds, and economies of scale may drive unit costs down, as reflected in the NREL cost forecasts that decline from 2.4% per year to 7.5% per year. Projected Base Case 2030 land-based wind costs are $70/MWh, ranging from $37/MWh at the low end with aggressive cost reductions and limited additional system upgrade costs, to $105/MWh at the high end, reflecting limited cost savings and higher system upgrade costs. As discussed above, there is likely to be limited wind capacity available in New England at the lower end of this range, and possibly at the Base Case cost projection, since major transmission infrastructure investments will be needed in Northern New England to access the highest quality resources.
- **Wholesale Solar:** Large-scale solar resources connecting directly to the transmission system have experienced significant cost reductions recently, falling from about $90/MWh just a few years ago to around $50/MWh for the recently contracted Gravel Pit Solar project in Connecticut. Because of this trend, our wholesale solar cost projections account for all of the identified references points, but are weighted towards the most recent contract price. Similar to wind resources, future solar costs must account for the ITC decrease to 10% over the next few years, as well as the wider industry trends in developing and constructing solar resources in Rhode Island and New England. NREL forecasts cost declines for utility-scale solar of 1.3% per year at the low end and 7.8% per year at the high end. These factors result in a projected 2030 cost range of $38/MWh to $103/MWh, with a Base Case value of $59/MWh.
- **Retail Solar:** The costs of retail solar vary significantly across the wide range of sizes of distributed solar resources built in Rhode Island. As further explained in the Technical Support Document, we relied on contract prices for solar resources through Rhode Island's Renewable Energy Growth programs. These range from $200/MWh to $300/MWh for solar resources less than 250 kW, and are $130/MWh to $150/MWh for solar resources over 1 MW (1,000 kW). We relied on the most recent allocation of capacity across the RE Growth solar categories to develop a blended retail solar cost estimate. NREL projects the most significant cost declines for retail solar of 8.7% per year, but includes an upper end cost estimate that reflects only limited cost reductions. In addition, interconnection costs have been rising quickly in Rhode Island, based on data provided by National Grid. These factors result in a 2030 cost range of $69/MWh to $189/MWh, with a Base Case projection of $107/MWh for a mix of retail solar resources.

To facilitate comparison of the cost ranges across the candidate resources, **FIGURE 7** shows the cost projections for each resource type for 2030, indicating the Base Case cost for each technology (diamond markers) within the potential range (bar). Although there is considerable uncertainty in the cost of all the resource types, and this uncertainty expands over time to 2030, Figure 7 shows that the resource acquisition costs of the three utility-scale resources (land-based wind, offshore wind, and wholesale solar) have similar cost ranges, despite being driven by factors specific to each resource. No one of these stands out as the lowest cost option. Over the next decade, it is not clear which, if any, of these resources may prove to have the lowest total cost, and cost variability from project to project within types may well mean that these technologies continue to be competitive with one another. What does seem clear is that projected resource acquisition cost and cost uncertainty is considerably higher for retail solar – likely to be on the order of $40/MWh to $50/MWh higher than for the utility scale resources. This cost difference primarily reflects the lack of scale economies for smaller facilities, and potentially higher costs due to the program structure through which they are acquired.

FIGURE 7: 2030 RESOURCE ACQUISITION COSTS

Note: Reflects the levelized $/MWh cost of a new resource online in 2030, at Base Resource Cost, with range reflecting alternative High and Low Resource Cost assumptions.

Resource Market Value

The costs of future renewable energy procurements, assessed above, will be partly offset by the market value of the products those resources provide – energy, capacity, and RECs – which will then not need to be acquired from the regional wholesale markets. [48] Below, we summarize the components of market value for each of the candidate resources.

Energy Market Value: ISO-NE operates regional wholesale electricity markets where generation facilities sell their power and load serving entities purchase it on behalf of customers. The energy market sets hourly and sub-hourly prices for energy delivered to the transmission system. Due to the different nature of solar and wind generation which produce power at different times, the market value of the resources differ. These differences figure into the ultimate above-market costs of each resource.

To determine the energy market value of these resources, we developed a New England-wide, long-term power system simulation model using The Brattle Group's in-house capacity expansion model, GridSIM. The GridSIM model optimizes the buildout of generation resources that will be developed over time and how they will be dispatched at an hourly level, reflecting the most recent information available

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[48] Potential ancillary service revenues are not included, since renewable generation typically provides few ancillary services and earns very little market revenue from them.

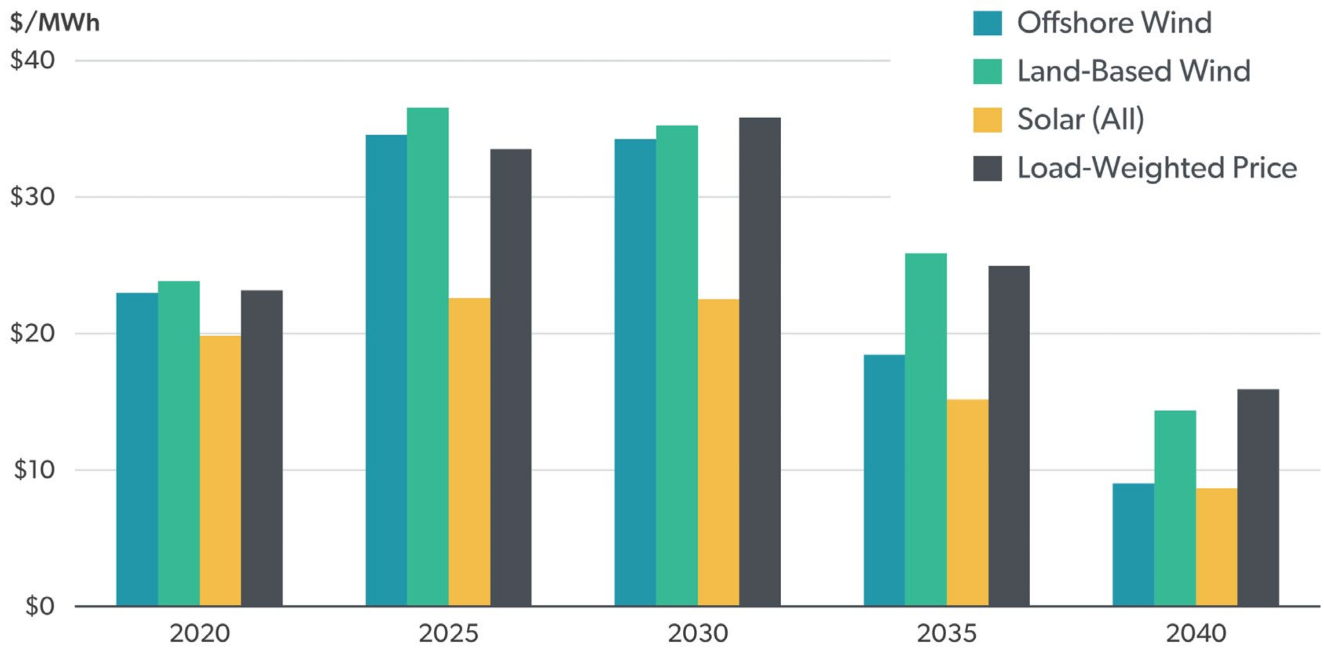

FIGURE 8: PROJECTED AVERAGE ENERGY MARKET REVENUES BY RESOURCE TYPE

concerning renewable energy resource additions, fossil fuel resource capacity and performance, electricity demand, and fuel prices. In addition, we account for renewable energy and GHG emissions policies across the New England states. GridSIM forecasts (among other things) an hourly energy price profile for each year simulated. We use these energy prices to estimate the future energy market value of the candidate renewable energy resources. Prior to analyzing future years, we compared near-term prices to recent historical prices to to verify that the model properly reflects the fundamentals of the regional power system. Details of the New England GridSIM model are included in the Technical Support Document.

FIGURE 8 shows the projected average energy market value for wind and solar resources in New England over time. For a given technology, this is the weighted average hourly price, with weights determined by that technology's generation output in that hour. Since they produce in different hours that have different prices, the technologies do not earn the same average revenues. For reference, the load-weighted price is determined similarly with weights determined by Rhode Island load in each hour. All of the resource types earn similar market value ($20 - $25/MWh) in 2020, but then diverge in 2025 and 2030 as natural gas prices (which set power prices, particularly in the early years) rise from their 2020 lows. New England gas prices are highest in winter, and wind produces more energy in the winter (solar produces more in summer); this allows wind to earn relatively more than solar on average, until late in the horizon.

In later years, as New England states' renewable energy goals rise, increasing renewable energy penetration of all types tends to push prices down in the hours when renewables generate most, reducing their average energy revenue. The average price for load also decreases, though to a lesser extent since prices are not pushed down in all hours. The higher energy market value for offshore wind and land-based wind reduces the above-market costs of these resources compared to wholesale and retail solar.

Capacity Market Revenues: In addition to their energy generation, renewable energy resources contribute generating capacity, which helps to maintain a reliable New England power system. For instance, solar supports the system by

Hourly Generation vs Load: Implications for Storage and Market Price Risk

The hourly generation profile of renewable resources does not generally match the hourly load profile particularly well. This is true for Rhode Island, and also at the New England level. This raises two important issues – one long-term, New England-wide question about how generation and load will be balanced on a system that will be dominated by intermittent renewable generation, and a second, potentially nearer-term issue for Rhode Island regarding the cost and cost risk implied by the hourly mismatch, even before significant issues arise at the system level.

Different renewable resource types have different hourly generation profiles, relative to the hourly shape of load. By choosing a renewable resource mix whose hourly generation profile matches load at least reasonably well, this issue can be partially mitigated. One way to illustrate this is shown in **FIGURE 9**. This uses offshore wind and solar as examples, and shows a hypothetical net load duration curve for each of the technologies (solid lines). The curves show the hourly difference between Rhode Island's load shape and the generation shape of the technologies. They are scaled for this hypothetical exercise so that total generation equals total load, and the hours are ranked by net load, independently for each technology. Where the curves are above zero at the left indicates hours in which load exceeds renewable generation.

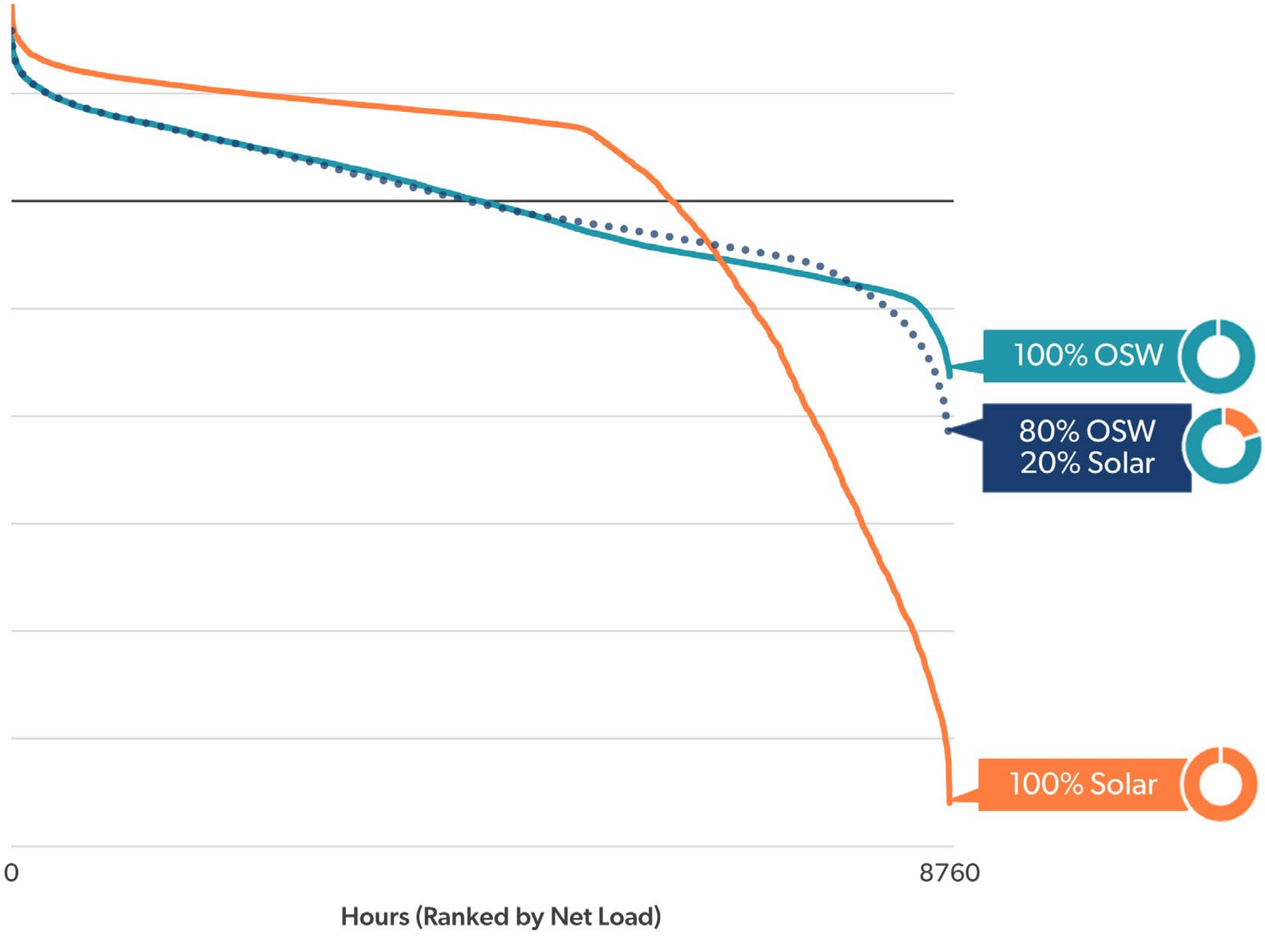

FIGURE 9: ANNUAL NET LOAD DURATION CURVES (NET LOAD = LOAD – RENEWABLE GENERATION)

Note: Hourly generation profiles are the same for Wholesale and Retail Solar, so their Net Load is also the same.

On the right, generation exceeds load (not necessarily the same hours for wind as solar). For each curve, the area under the curve and above the zero line (left side of the figure) is equal to the area above the curve on the right side. A curve that is closer to the zero line (lower on the left and higher on the right) represents a better hourly match with load. Conceptually, storage can be one way to address this mismatch, storing energy in hours of excess for use in hours of shortage. That ends up being a complicated question, since the usefulness of storage depends not only on the hourly mismatch, but also on whether the excess and shortage hours are close in time (day to night) or farther apart (summer to winter). But this simple illustration suggests the magnitude of the issue that must ultimately be faced.

Comparing the technologies, solar clearly has much larger hourly mismatches than offshore wind. Its output is concentrated into fewer hours, only daytime and mostly summer, with most hours having no solar generation at all. In order to provide enough total generation to match annual load by itself, solar would generate far more than load in a small number of hours – sunny hours with low load, like spring afternoons – but would generate much less than load (often zero) in the majority of hours. This does not mean that solar is not a useful renewable resource, however. Due to the hourly diversity between wind and solar generation, a mix of wind with some solar may offer a somewhat better match than just wind. The blue dotted line shows the net load curve of a mix of 80% offshore wind with 20% solar (by energy); its match with load is as good or better at most times, other than a small number of spring afternoon hours when generation greatly exceeds load.

This is admittedly a very rough metric; it does not account for short-term vs seasonal differences in the timing of the excess and shortage hours, for other generation types (hydro, nuclear) and their generation profiles, or for potential transmission constraints, etc. But it does suggest that this question of hourly matching will limit the amount of solar generation the New England system can usefully accommodate. While some solar can improve the hourly match, as the overall energy share of solar goes beyond about 30%, the hourly match with load begins to worsen.

Rhode Island is a small part of New England (about 6%), so its choice of resource types will be well within any system-wide limits on the best balance of renewable resource types. If Rhode Island did choose a solar-heavy portfolio, there will be ample opportunities for the rest of the system to balance this by choosing more non-solar resources. Even so, a mismatch would create price risk for Rhode Island ratepayers, which is the second, potentially nearer-term issue.

Once it reaches 100% renewable, Rhode Island's total renewable generation will equal its total load on an annual basis, but in each particular hour its renewable generation will be either higher or lower than its load. The excess or shortage will be sold into or purchased from the New England electricity market, at the prevailing hourly price, and hourly energy prices differ, sometimes significantly. This hourly quantity mismatch thus has economic impacts for ratepayers. Over time as renewable penetration increases across the region, prices in hours with high renewable generation will tend to fall (this was seen in Figure 8, where in later years the average price earned by each renewable generation type falls below the average for load.) The above-market cost calculations below take this into account by subtracting projected market revenues of the renewables, though that is only an estimate of the effect.* Customers face additional cost risk if hourly prices differ from these projections, and the risk depends on the magnitude and timing of the hourly mismatch and hourly prices. This suggests that there is good reason for Rhode Island to try to maintain a reasonably good match between the hourly generation shape of its renewable portfolio and its own load shape. With just the renewable resources already online and committed, Rhode Island already has enough solar to provide about 14% of its 2030 energy needs.

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* Another way to manage this mismatch in timing is with energy storage, such as batteries, though that also has a cost.

providing energy when the system needs it, such as in the afternoon on the hottest summer days. Renewable energy resources can receive payments for providing this value, which reduces the need to purchase capacity from other resources and reduces ratepayer costs. Based on the current rules under the regional Forward Capacity Market operated by ISO-NE, renewable energy resources supported by state programs that are unable to offer below a pre-determined price threshold (known as the Offer Review Trigger Price, or ORTP) must enter the capacity market through recently introduced "substitution auctions" instead of the primary auctions.[49] However, to date just 54 MW of renewable capacity cleared in the first two substitution auctions due to limited participation and low primary auction prices ($2/kW-mo).[50] The limited amount of renewable energy resources that have cleared in the substitution auctions has created concerns about the viability of this path for renewable resources participating in the capacity market, and capacity market structures more generally.[51]

Similar to the energy market value discussed above, the capacity market value that renewable resources realize can reduce the net costs of renewable generation to ratepayers. To estimate this value, we reviewed recent New England capacity market prices and the outlook for future capacity needs. Over the past five years, capacity prices have declined from $7/kW-month in 2016 to $2/kW-month in 2020, reflecting excess generating capacity in the system.[52] Prices are likely to remain low due to limited peak demand growth over the next decade. Based on these market conditions, we assume capacity prices will be approximately $4.5/kW-month, the average price over the past five years.[53] Because they are intermittent resources, renewable energy resources receive credit for a relatively small portion of their total nameplate capacity in the capacity market: 39% for land-based wind, 47% for offshore wind, and 19% for solar.[54] These values are likely to decrease in the future as more renewable energy resource additions shift the hours that drive reliability events. Given the uncertainty in whether renewable energy resources will be able to participate in the capacity market and the potential for their capacity credit to decrease with rising penetration, we discount the assumed revenues that renewables will earn from the capacity market by 50%. **FIGURE 10** shows the resulting capacity value across the candidate renewable resources, converted to an energy basis in $/MWh – on the order of $3/MWh to $4/MWh, and similar across technologies. Given the uncertainties in future market conditions, we considered a range of capacity value for renewables from $0/MWh if renewables do not clear the substitution auction to about $14/MWh, based on an equilibrium capacity price of $8.71/kW-mo and full realization of their current capacity credit values.[55]

Renewable Energy Credit (REC) Value: Qualified renewable energy resources create a REC for each megawatt-hour they generate, which they can then sell to entities across New England that must comply with renewable energy mandates set by each state. For example, under its Renewable Energy Standard, Rhode Island requires that load serving entities, such as National Grid and third-party providers, purchase 16% of their demand from renewable energy in

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[49] Renewable resources can directly enter the primary auction if their net costs are below the ORTP threshold.

[50] ISO-NE, 2018 Annual Markets Report, May 23, 2019, p. 20; ISO-NE, 2019 Annual Markets Report, June 9, 2020, p. 184.

[51] See, e.g., the New England Governors Statement on Electricity System Reform, October 14, 2020 (http://nescoe.com/resource-center/govstmt-reforms-oct2020/) and the New England States Vision Statement (http://nescoe.com/resource-center/vision-stmt-oct2020/).

[52] ISO-NE, Results of the Annual Forward Capacity Auctions, accessed December 14, 2020.

[53] Capacity prices developed in our long-term New England market simulations in GridSIM are also in the range of $4/kW-mo to $5/kW-mo for 2020 to 2030.

[54] Concentric Energy Advisors, Net CONE and ORTP Master DCF, November 24, 2020.

[55] Equilibrium capacity price is based on the Net CONE value estimated for the ISO-NE 2024-2025 Forward Capacity Auction. ISO-NE, Forward Capacity Market Parameters, November 10, 2020.

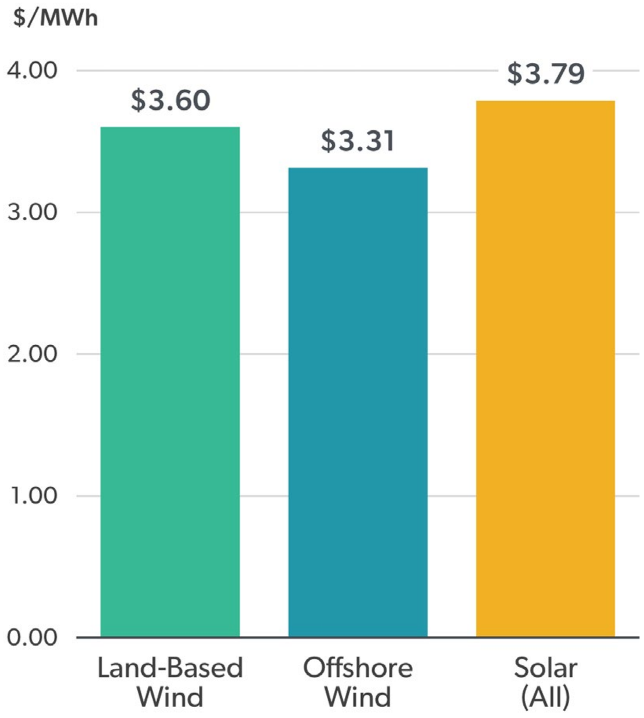

FIGURE 10: CAPACITY MARKET REVENUES – BASE CASE

Sources and Notes: Assumed average capacity price over past 5 auctions of $4.50/kW-mo; qualified capacity based on draft 2020 ISO-NE ORTP study: Concentric Energy Advisors, Net CONE and ORTP Master DCF, November 24, 2020

2020.[56] The qualified renewable energy resources can be in Rhode Island, other New England states, or neighboring jurisdictions that can deliver the generation to New England.

Over the past five years, New England REC prices have fluctuated from about $50/MWh to around $5/MWh and back, as shown in **FIGURE 11**. Since RECs are relatively short-term financial instruments representing renewable generation in a given year and traded at most a few years forward, REC prices depend primarily on the short-term balance of renewable energy generation and state RPS requirements. When total renewable generation exceeds REC requirements, REC prices are low; alternatively, when demand exceeds total renewable generation, even if that situation is short-lived, REC prices will be high (capped at each state's alternative compliance payment, or ACP).

In the future, REC prices will continue to be driven by the short-term balance of rising state-by-state mandates and rising quantities of renewable generation, driven by state procurements through long-term contracts and other similar programs (like Rhode Island's Renewable Energy Growth programs and offshore wind procurements). This dynamic makes it extremely challenging and perhaps futile to try to project future REC prices. Because of this, we developed a set of assumed REC prices that we use in our analyses. We reviewed historical REC prices, as well as the net costs of acquiring large-scale renewables like offshore wind and wholesale solar as determined by our analyses above. Based on these factors, we assume a Base REC price of $30/MWh.[57] We analyze a REC price range of $15/MWh to $45/MWh, consistent with both the range of recent historical prices and the uncertainty ranges of our resource costs analyses.

Evaluating the Candidate Renewable Resources

The next two sections use the information developed above to evaluate how the four candidate renewable energy resource types will affect Rhode Island. This is illustrated stylistically in **FIGURE 12**. The costs of acquiring renewable energy generation resources and the market revenues they earn from the electricity market are combined to estimate the above-market costs to Rhode Island ratepayers in **SECTION III.B.** In addition, developing and paying for renewable energy resources will have broader effects on the Rhode Island economy, including the state's Gross Domestic Product (GDP) and local employment. The cost information, plus additional information on the construction expenditures for developing renewable energy projects, as well as relationships within the local economy, are used to model these economic impacts

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[56] Rhode Island Office of Energy Resources, Renewable Energy Standard (2004), accessed December 14, 2020.

[57] As an independent reference point, the recent analysis of the ISO-NE Offer Review Trigger Prices assumed REC prices of $29/MWh, similar to the Base REC price assumption developed for this study. Concentric Energy Advisors, Net CONE and ORTP Master DCF, November 24, 2020.

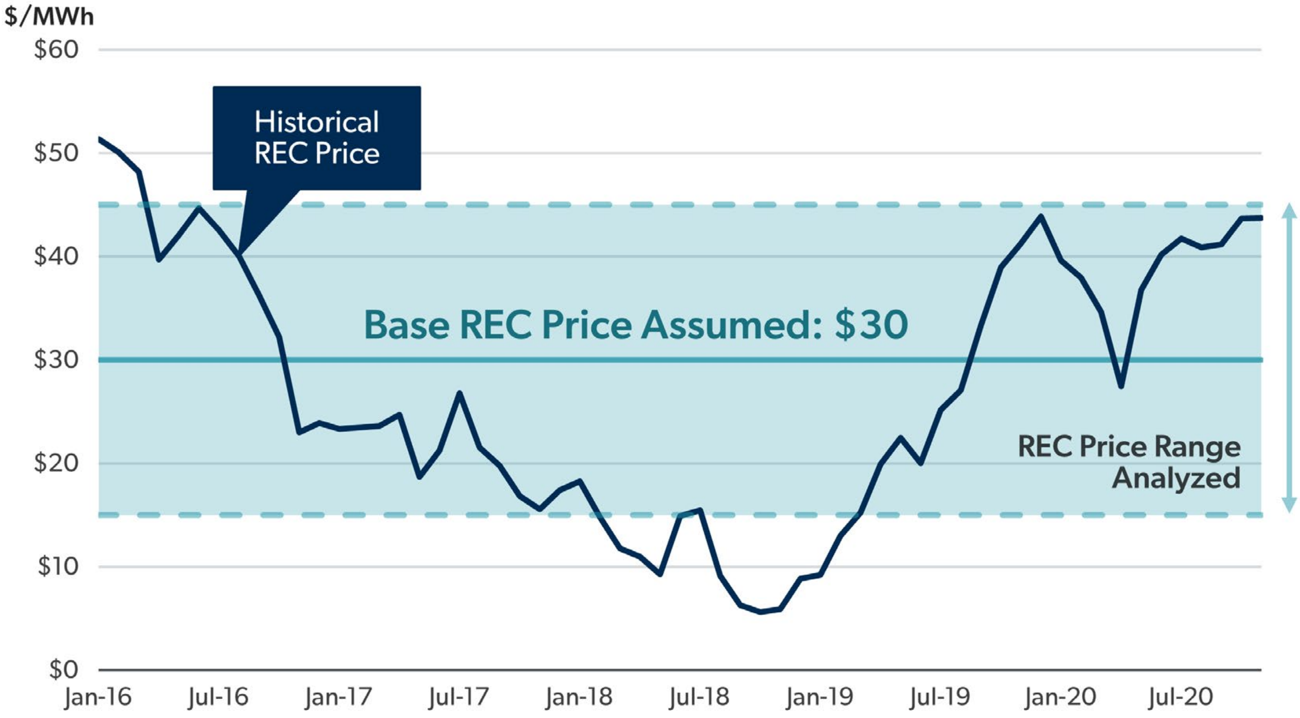


FIGURE 11: HISTORICAL RHODE ISLAND REC PRICES (2016–2020)

Source: S&P Global Market Intelligence, accessed November 23, 2020.

and estimate the resulting GDP and employment effects in **SECTION III.C**.

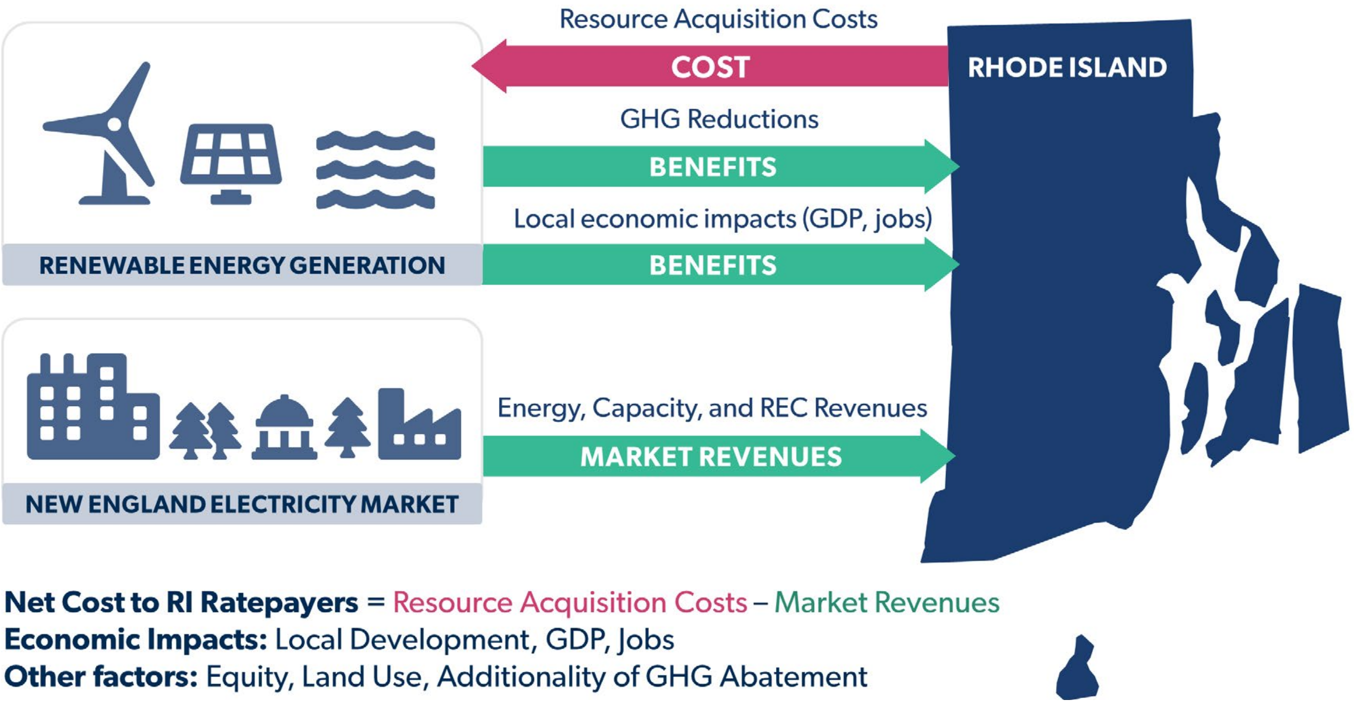
The two metrics used, above-market costs and economic impacts, are consistent with Executive Order 20-01. They are applied to the four Technology Bookends, hypothetical ways to fill the entire 2030 renewable energy gap with a single renewable resource. The above-market cost analysis considers the cost of going from the existing RES (16% now, rising to 38.5% in 2035) to 100% renewable (implemented through a 100% RES) by 2030. In this analysis, we show for comparison what it would cost to fill the gap entirely with RECs purchased from the market, at the assumed REC price of $30 (alternatively, $15 or $45). The local economic impact analysis, in contrast, takes a comparative perspective, assessing the economic impacts of each of the renewable technologies relative to purchasing market RECs at the assumed REC price ($15, $30, or $45). In doing this, it shows the relative economic impacts of alternative ways to reach the 100% goal, given that the goal must be achieved.

SECTION III.D. which follows applies these same evaluation metrics to several Technology Portfolios developed to represent alternative ways of filling the gap with combinations of different resource types. These Technology Portfolios are likely to be more illustrative of actual paths that might be followed than the single-resource Technology Bookends.

Of course, other factors such as equity and land use are also important, and must be considered in addition to the cost and economic analyses of the upcoming sections. These issues may be specific to particular projects and thus difficult to generalize to technology types, or may not be directly related to the choice of renewable technologies.

III.B Above-Market Costs of Technology Bookends

The first metric we consider for the candidate renewable energy resources identified is the impact on Rhode Island



Net Cost to RI Ratepayers = Resource Acquisition Costs – Market Revenues
Economic Impacts: Local Development, GDP, Jobs
Other factors: Equity, Land Use, Additionality of GHG Abatement

FIGURE 12: IMPACTS OF PROCURING RENEWABLE ENERGY TO ACHIEVE 100% BY 2030

electricity ratepayer costs. Ratepayer cost impacts account for the incremental costs of acquiring renewable energy to serve the state's entire electricity demand. This can also be referred to as the "above-market costs" of renewable energy resources, relative to purchasing non-renewable energy beyond the current REC requirement. We calculate the above-market costs of each of the candidate renewable technologies based on its resource acquisition costs, deducting its energy and capacity market value. The REC value of a technology is not deducted from the above-market cost, though the resulting above-market cost can be compared to the cost of purchasing market RECs. To illustrate this in the context of the 100% goal, we consider four Technology Bookends, one for each resource type considered. Each Bookend is defined as the amount of new renewable generation of the given resource type needed to fill the entire renewable energy gap to achieve 100%. We use this to measure the overall cost of increasing renewable energy to achieve 100% by 2030, relative to achieving the current RES. It does not include the costs of achieving the current RES, which is an existing requirement.

FIGURE 13 shows the total above-market costs to achieve 100% renewable electricity in Rhode Island with each of the Technology Bookends, in net present value (NPV) terms for 2020 to 2040, using a 3% real discount rate.[58] First, as a reference point, we show the ratepayer cost of purchasing unspecified RECs from the market at the assumed $30/MWh price has an NPV of $1,400 million. If RECs cost $15/MWh or $45/MWh, that value changes to $700 or $2,100 million, respectively. Alternatively, the four Bookends show the cost of filling the renewable gap with the four alternative candidate

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[58] We assumed a 3% (real) discount rate that reflects a commonly used "social discount rate", such as is often used to determine the value of avoided greenhouse gas emissions. While there is no "correct" discount rate per se, there is a large literature discussing the use of a "social discount rate" to evaluate policy that takes into account various societal issues, rather than reflecting purely private decision making. Social discount rates are generally in the range of 2.5-7% (real), with some arguing for 0%. U.S. estimates of the social cost of carbon use discount rates of 2.5%, 3% and 5%; see Resources for the Future, Social Cost of Carbon 101, August 1, 2019. See also OMB Circular A-4, September 17, 2003, which includes an in-depth discussion of the rationale for using various discount rates.

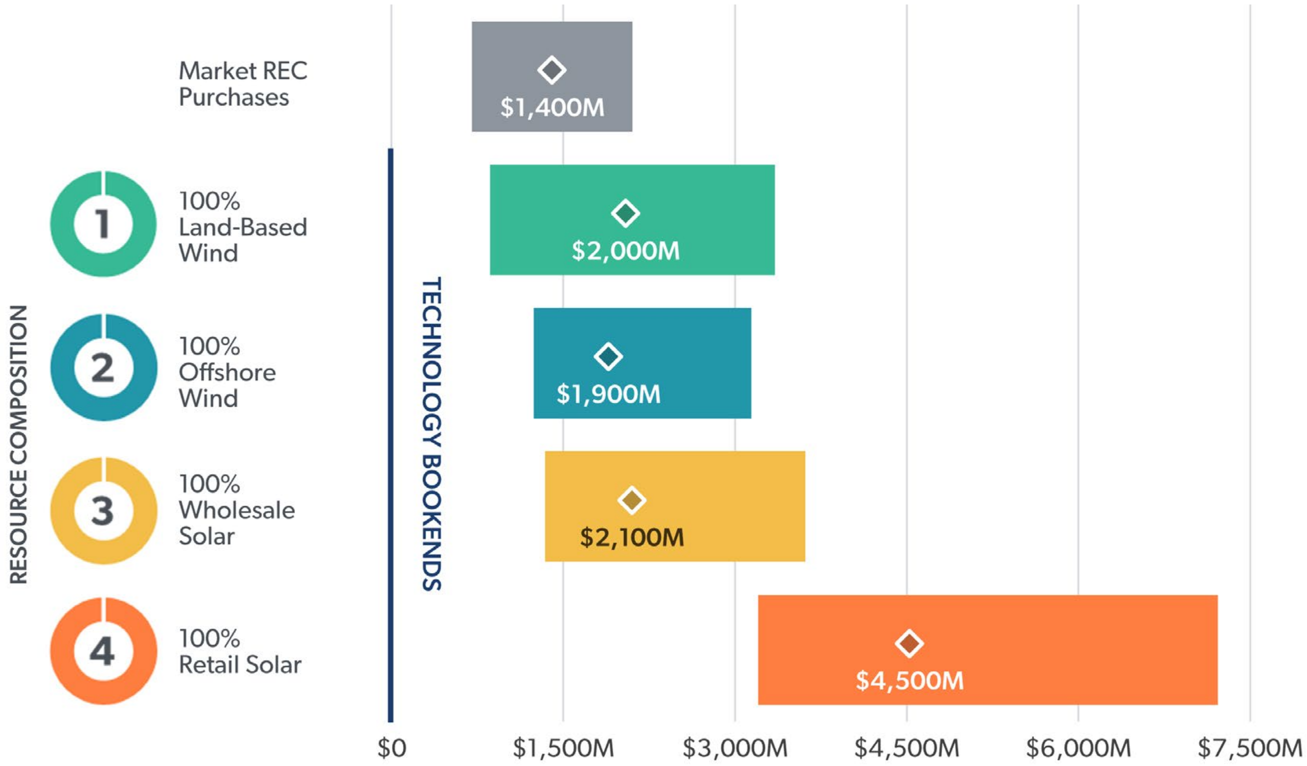

FIGURE 13: NPV OF ABOVE-MARKET COSTS (2020–2040) OF ACHIEVING 100% RENEWABLES; BOOKENDS
(NET OF ENERGY AND CAPACITY REVENUES, NOT RECS)

Note: Ratepayer costs reflect the total incremental costs of achieving 100% net of energy and capacity revenues.

renewable energy resources.[59] For each Technology Bookend, the figure shows the Base Case above-market costs (diamond marker) and the potential range of costs (shaded bar) that reflects uncertainty in the resource acquisition costs, as was reflected in Figures 6 and 7 above. Purchasing market RECs may be the lowest cost approach to achieve 100% goal by 2030 (or it may not), but as described below, this approach may not align with several of the guiding principles outlined above. The Base Case costs of the three utility-scale resource Bookends are similar to one another, with above-market costs of $1,900 million to $2,100 million over twenty years. The Retail Solar Bookend, however, results in a materially higher above-market costs, $4,500 million over this timeframe. This reflects its significantly higher resource cost as identified above.

Among the utility-scale resources, the range in ratepayer costs reflects the significant uncertainty in the outlook for renewable resource costs in Rhode Island and New England, as described above. At the low end, above-market costs of the utility scale resources are about $900 million to $1,300 million, which reflects significant cost declines for each resource, and system upgrade costs reflective of the recent past. On the high end of the cost range, renewable resource costs do not decline significantly from today, and system upgrade costs are significantly higher, resulting in net ratepayer costs of $3,100 million to $3,600 million.

The similar Base Case cost estimates and ranges signal that no one of these technologies is currently projected to be the lowest cost renewable energy resource. This conclusion is similar to the comparison above of resource acquisition costs, but it now includes the market value of the resources.

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[59] While our analysis continues to account for the future incremental costs of the renewable resources that are brought online to achieve 100% by 2030, we do not include the costs of additional new resources that are likely to be needed beyond 2030 to maintain 100% as load grows further.

Pros/Cons of Meeting 100% via Market Purchases of Short-term RECs

Market purchases of short-term RECs may result in lower costs of meeting 100% RES (though it is also possible it might not, given reasonable uncertainties). However, REC purchases might also have other less desirable impacts, including:

- Lower GHG impacts, if RECs are from renewable resources that are not entirely additional (e.g., resources built ahead of other states' needs). RECs may be more likely to be inexpensive when the renewable generation is not additional.
- Limited support for local renewable resources (potentially giving up in-state economic activity).
- Increased ratepayer exposure to volatile REC prices via market REC purchases.

Over the next decade, the costs of the different resource types could diverge, based on global and local markets for each resource, the local labor market, the need for system upgrades and the approach Rhode Island and other states take for planning the future regional power system. The cost diversity that has been observed across specific projects is also likely to continue. It will be valuable for Rhode Island to continue to seek out opportunities to use competition among resources, across types as well as within them, to identify the particular technologies and projects that are most attractive for the state. This suggests that it will be valuable for Rhode Island to continue to seek out opportunities to use competition among resources, across types as well as within them, to identify the particular technologies and projects that are most attractive for the state.

The range of impacts of a broader set of uncertainties is shown in **FIGURE 14**, using the Offshore Wind Technology Bookend as an example. The figure shows that resource acquisition costs are the primary uncertainty, followed by the future energy market revenues and capacity market revenues. Renewable resources have a higher net costs when market prices are lower, such that if future natural gas prices are $2/MMBtu lower in 2030, reducing average energy prices by $12/MWh, the above-market costs of achieving 100% renewables would increase by about $320 million. Similarly, for potential changes in the capacity market that may affect the capacity value captured by renewables, above-market costs could decrease by about $390 million if they earn full capacity credit and capacity prices rise, or costs could increase by about $140 million if the renewable resources earn no capacity value. Uncertainty in load is expected to have a limited impact on costs.

FIGURE 15 converts the potential impact of the above-market costs into Rhode Island retail rate impacts, also showing the resulting increase in monthly costs for a typical residential customer. The rate impacts of the Technology Bookends are similar for Offshore Wind, Land-Based Wind, and Wholesale Solar, at roughly 1 to 5 cents/kWh, while Retail Solar impact is higher at 4 to 10 cents/kWh. These rate increases would increase a typical residential monthly bill by about $11 to $14 with utility-scale renewables, or by $32 if the entire gap is filled with retail solar.

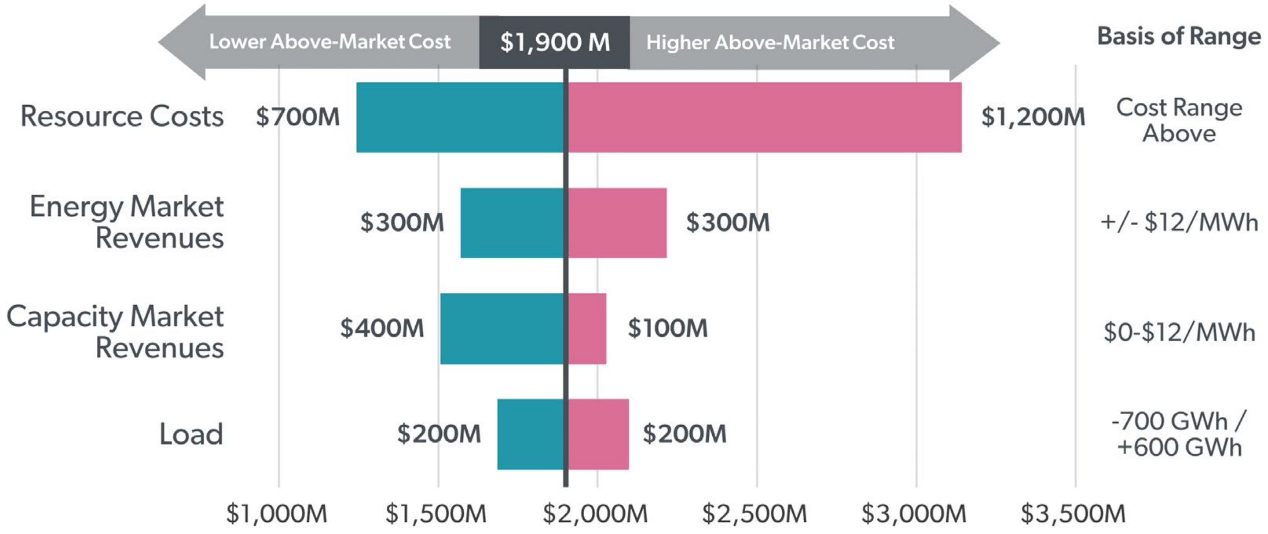

FIGURE 14: SENSITIVITY ANALYSIS OF ABOVE-MARKET COSTS (OFFSHORE WIND TECHNOLOGY BOOKEND)

Note: Above-market costs reflect the total incremental costs of achieving 100%, net of energy and capacity revenues.

NEM/VNM Cost Shifts

Most of Rhode Island's renewable energy procurement programs are run by National Grid, with the above-market costs spread across all ratepayers. However, certain customers are able to add renewable energy resources through either net energy metering (NEM) or virtual net energy metering (VNM) arrangements. These result in cost shifts from the NEM or VNM customer to remaining customers. Under NEM and VNM programs, customers can offset a portion of their utility bill by installing solar resources on-site (such as on the roof of their house) and thus reducing their metered demand, or by receiving bill credits for VNM resources located off-site. The cost shift occurs because the avoided payments resulting from the addition of the NEM or VNM resource are greater than the actual costs avoided by reducing the customer's demand. The difference is the costs that are shifted to other, non-participating customers.

Based on current projections by National Grid, Rhode Island is expected to have about 400 MW of NEM or VNM generation by 2022-23, which equates to about 500 GWh per year of solar generation. The majority of this (about 85%) is from VNM facilities, which tend to be larger solar facilities (up to 10 MW) as compared to residential rooftop solar (5 – 15 kW). VNM is limited to certain customers who account for around 6% of total Rhode Island load. Based on estimated NEM credits and volumetric rates, NEM/VNM customers accounting for 400 MW of NEM/VNM resources cause a cost shift of about $55 million per year to non-NEM/VNM customers, which increases their rates by 0.8 ¢/kWh.* Resources from the RE Growth Program or those acquired through utility-scale long-term contracts do not result in similar cost shifts.

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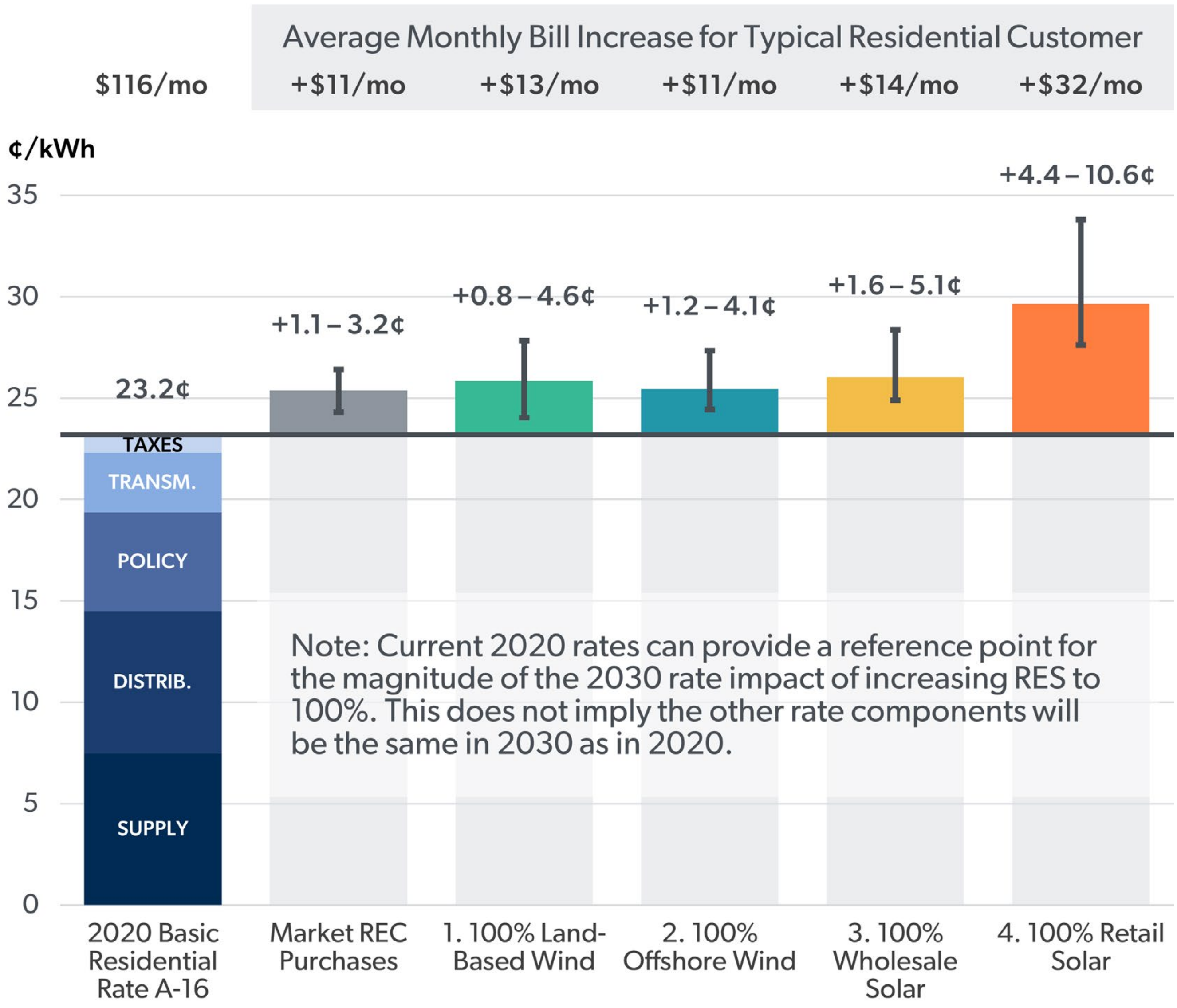
* We assumed a volumetric retail rate of 20.4 ₵kWh and net energy metering credits of 17.0 ₵kWh based on our analysis of current Rhode Island electricity rates and regulations. We assumed a total market value of $60/MWh, including energy, RECs, and capacity revenues



Note: Current 2020 rates can provide a reference point for the magnitude of the 2030 rate impact of increasing RES to 100%. This does not imply the other rate components will be the same in 2030 as in 2020.

FIGURE 15: 2030 RATE IMPACTS OF 100% RENEWABLE ELECTRICITY

Notes: Assumes typical residential customer consumes 500 kWh/mo.

III.C Economic Impact of Technology Bookends - GDP and Employment

The second key metric we consider for evaluating renewable energy technologies and portfolios is their economic impact – their effect on Rhode Island's gross domestic product (GDP) and in-state employment. The economic impacts are influenced by the ratepayer above-market costs, and consider how the above-market costs propagate throughout the economy. In addition, the economic impacts consider the effects of the in-state investments and economic activity that occur when developing renewable energy generation projects in Rhode Island.

We use IMPLAN to estimate the economic impacts of alternative ways to reach the 100% goal. IMPLAN is a commercial input-output model, widely used by federal, state, and local governmental agencies to measure the impacts of regulatory changes and major infrastructure investments.[60] IMPLAN estimates the economic impacts of one specified alternative compared to another – e.g., how local GDP or employment would differ between two specified alternatives.[61]

The economic impact analysis compares potential portfolios of renewable energy resources against the alternative of meeting 100% renewables entirely through market REC purchases, at an assumed reference REC price (nominally $30/MWh; we also consider cases with REC prices of $15/MWh and $45/MWh). This allows us to evaluate each of the alternative resource mixes against the same reference case, thus facilitating comparisons between alternatives. Because of this, the economic impact analysis does not yield the overall economic impact of reaching 100% (as compared with not achieving it), but rather considers the impact of how 100% is achieved, given the 100% goal.

The impact of alternative renewable resources on Rhode Island GDP and employment occurs through three potential channels:

1. *Construction Expenditures* before the project comes online (for in-state projects);
2. *O&M Expenditures* during operation (again for in-state projects); and,
3. *Tariff Impacts paid for by Rhode Island* ratepayers throughout the life of the contract.

The construction and O&M expenditures associated with an in-state project will cause inflows into several Rhode Island economic sectors. For example, a solar project would involve specific amounts of construction labor, cement, structures, solar panels and inverters, etc. Similarly, an offshore wind project would involve onshore and offshore labor, structures, wind turbines and blades, etc. Some of these expenditures would occur in Rhode Island, while some would go out of state (e.g., construction labor vs. solar panels), as specified in NREL's JEDI model (see sidebar: Economic Impacts Can Be Project-Specific). The direct expenditures in these sectors interact with other sectors through the economy, each causing changes in economic activity that are then tracked by IMPLAN to determine their overall effects on Rhode Island GDP and employment.

The tariff impacts reflect the economic effects of the incremental above-market costs of the acquired renewable energy resources as those costs filter through the economy. These above-market costs are assessed relative to buying market energy and RECs, and they may be negative. Contracting for a particular renewable energy resource may be cheaper than buying market energy plus RECs, if the resource is low cost or the REC price is high. Thus, a project's tariff impact would be negative if consumers pay less for the project than they would to buy comparable energy and RECs from the market. Since producers and consumers pay less for electricity, they have more to invest and spend in other ways, resulting in positive impacts on GDP and employment. If the project's cost is higher than market energy plus RECs, it increases consumer costs relative to the market benchmark, resulting in negative economic effects due to the decreased investment and spending.

A project's economic impact varies considerably over time. The initial construction phase of an in-state project results in a boost to local GDP and employment. Once construction ends and the project comes online, the net GDP and employment benefits diminish and can even reverse if the project has significant above-market costs that offset the benefits of the ongoing O&M expenditures.

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[60] For more information on IMPLAN, see www.implan.com. We supplemented IMPLAN's sector allocations for renewable energy resources with data from the JEDI model (Jobs & Economic Development Impact), developed and maintained by NREL, the National Renewable Energy Laboratory. See https://www.nrel.gov/analysis/jedi/.

[61] IMPLAN is an input-output model rather than a dynamic equilibrium model, and thus does not project the future trajectory of the economy in absolute terms. Still, since there is a level of stability in the underlying economy over time, IMPLAN provides a reasonable estimate of the relative economic impacts of one alternative compared to another.

Economic Impacts Can Be Project-Specific

IMPLAN (like any economic impact model used in this way) uses typical or characteristic allocations of expenditures to sectors in order to model a representative project of a given technology. However, the actual local Rhode Island impact of any particular project will depend on how that project is executed. Any specific project may have a different mix of local vs out-of-state suppliers and labor that lead to different GDP and jobs impacts for Rhode Island, and this may influence the attractiveness of the project for Rhode Island. For instance, two otherwise similar solar projects may have different economic impacts for Rhode Island if one utilizes mostly in-state labor and materials, and the other relies more on out-of-state resources. The results presented here reflect a typical project of each of the resource types, but there may be project-to-project variability in impacts.

We estimate the net present value of the GDP effects for comparing across technologies and portfolios, discounting all impacts from the time they occur to the present (again using a 3% real discount rate) to facilitate summarizing and comparing the impacts of the technologies. As a second summary measure, the net employment impact is also included, expressed in undiscounted job-years.[62]

All these impacts are assessed over the period 2020-2040. While acknowledging that the 2040 horizon cuts off part of the operating life of later renewable energy additions, projections of costs and economic benefits beyond that becomes highly uncertain, particularly because of the upcoming changes in the electric power industry. Using the same time horizon and discount rate for all portfolios helps to keep the results comparable despite the challenges of projecting so far into the future; the effect of still more distant years would be diminished by discounting in any case.

To illustrate the analytic approach in the economic impact analysis, we first apply IMPLAN to a single hypothetical project. We then apply it to the Technology Bookends defined above, which leads to several observations about the economic impacts of each of the technologies on its own. Later, we apply this same approach to a number of representative Technology Portfolios that use combinations of technologies to fill the 2030 renewable energy gap.

We start by considering the economic impact of a hypothetical 600 MW offshore wind project such as might result from Rhode Island's recently announced request for proposals (RFP) for offshore wind. The upper panel of **FIGURE 16** illustrates the GDP impacts of this project as evaluated with IMPLAN, showing the three categories of impacts considered. For the

Additional Economic Benefits

The economic impact analysis here considers only the impacts that are attributable to the renewable resources considered. It does not include potential consequential economic benefits. For instance, developing offshore wind resources to satisfy Rhode Island's own 100% goal may have additional benefits if it contributes to seeding a new "export" industry in Rhode Island and across Southern New England. Additional economic benefits could accrue to the state from future offshore wind projects procured by other New England states in Rhode Island waters or developed and serviced from a Rhode Island port. Those benefits are not reflected here, though would be positive in terms of local GDP and employment.

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[62] One job-year is a full-time job for one year.

Interpreting the Tariff Impact

The Tariff Impact values presented here are most useful for comparing one project or portfolio to another. The absolute values of these impacts are less meaningful because the values are measured relative to an assumed reference point – in particular, relative to an assumed REC price. Actual future market REC prices are extremely difficult to project and are likely to vary considerably over time. This means that the absolute value of the Tariff Impact calculated here may not reflect the future realized differences between resource cost and the market value of energy and RECs. Nonetheless, the relative values of these impacts, comparing one technology or Portfolio to another (within the uncertainties on technology costs and project-to-project cost variability), are meaningful and can be useful for understanding the relative economic impacts of alternative renewable resources. The Base REC price assumption adopted here, $30, may be conservatively low, as it is moderately below the corresponding costs of the three utility-scale renewable technologies considered. This leads to the renewable resources generally appearing in this analysis to be slightly more costly than market RECs, so that the Tariff Impact is slightly higher, resulting in a negative GDP and jobs impact. We are not projecting that acquiring renewable resources will necessarily be more costly than market REC purchases (though that is certainly possible); rather, this simply results from the $30 REC price that is used as a reference assumption.

three years before the assumed 2027 online date, the project's Construction Expenditures (green bars) create significant economic activity and GDP benefits for the state. Once the project is online and for the duration of its operation, O&M Expenditures (blue bars), which are considerably smaller in magnitude, create additional positive annual benefits. The Tariff Impact (grey bars) here is roughly zero for the early years of project operation, and then is modestly negative for subsequent years due to declining market value of the offshore wind generation. It is important to note that this Tariff Impact is a relative value, compared to an assumed reference case in which the 100% renewable electricity goal is achieved instead through market REC purchases, and is most useful for comparing across resources or Portfolios. (See sidebar on how to interpret the Tariff Impact effects.) The solid black line represents the net annual GDP impact, combining all three categories of impacts.

The lower panel of Figure 16 shows the employment impacts of the same 600 MW offshore wind project. The three components (Construction Expenditures, O&M Expenditures, and Tariff Impacts) and the profile over time are directionally very similar to the GDP impacts. As with the GDP measure, the Tariff Impact on jobs is most relevant for making relative comparisons between projects or portfolios, rather than for interpreting the absolute value.

In the previous section, we defined four Technology Bookends, each as a hypothetical way to fill the renewable energy gap entirely with a single technology type: Land-Based Wind, Offshore Wind, Wholesale Solar, or Retail Solar. To make these Bookends comparable, each generates the same amount of renewable energy in each year and fills the 2030 renewable energy gap by adding new capacity in equal increments in years 2025-2030.[63]

FIGURE 17 shows that the GDP impact of the Offshore Wind Technology Bookend, which assumes the addition of about 170 MW of new offshore wind resources per year from 2025 to 2030 is about +$700 million in present value terms. Similar to the previous figures, the construction expenditures provide early benefits that are now spread over multiple

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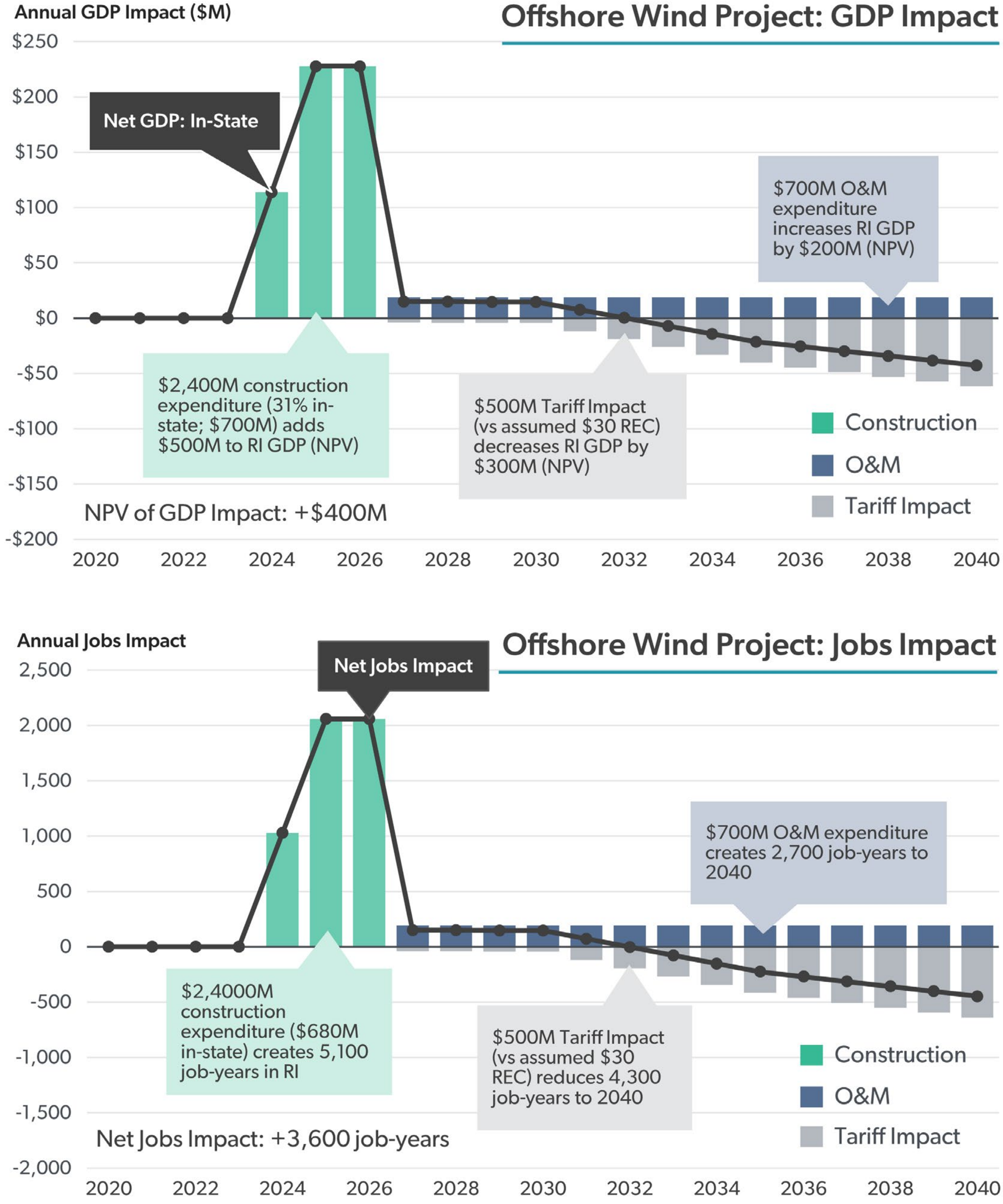
[63] For offshore wind in particular, this profile is considerably less "lumpy" than actual projects that would fill the gap, since offshore wind projects tend to be quite large.



Offshore Wind Project: GDP Impact

$700M O&M expenditure increases RI GDP by $200M (NPV)

$2,400M construction expenditure (31% in-state; $700M) adds $500M to RI GDP (NPV)

$500M Tariff Impact (vs assumed $30 REC) decreases RI GDP by $300M (NPV)

NPV of GDP Impact: +$400M

Offshore Wind Project: Jobs Impact

$700M O&M expenditure creates 2,700 job-years to 2040

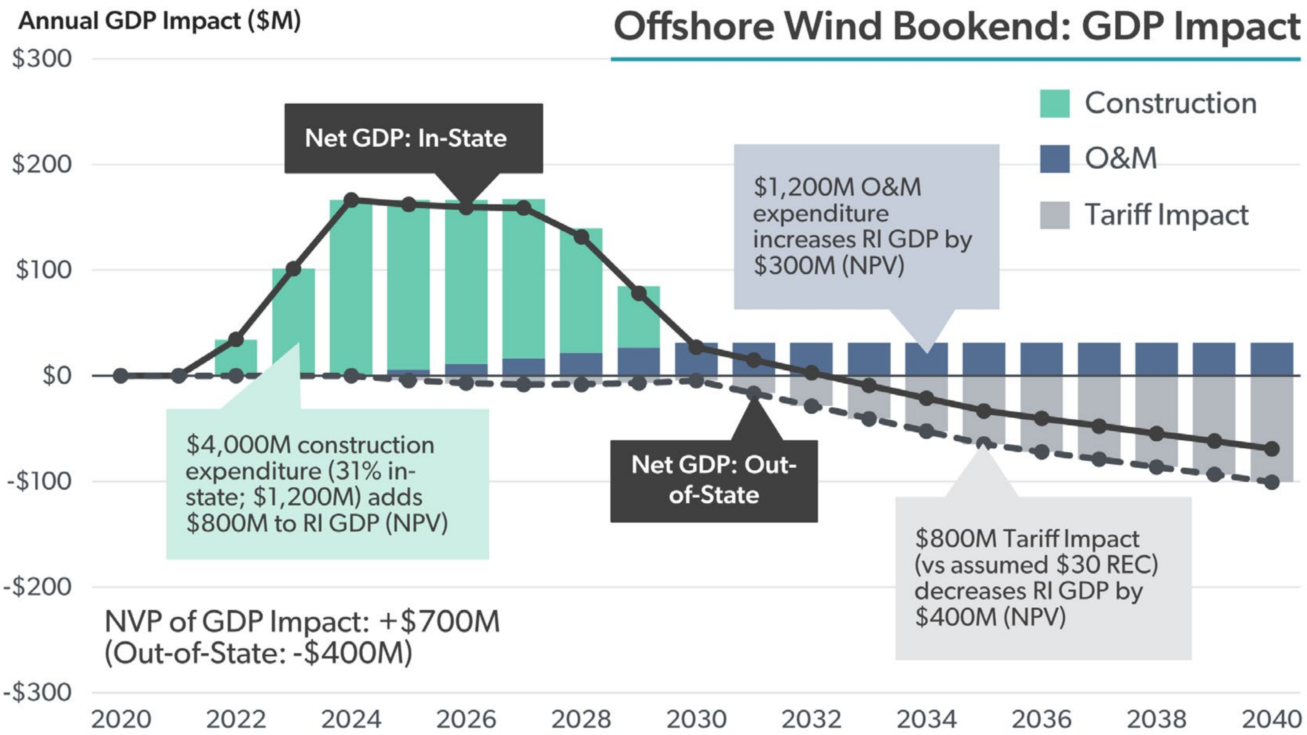
$2,4000M construction expenditure ($680M in-state) creates 5,100 job-years in RI

$500M Tariff Impact (vs assumed $30 REC) reduces 4,300 job-years to 2040

Net Jobs Impact: +3,600 job-years

FIGURE 16: GDP AND EMPLOYMENT IMPACTS OF 600 MW OFFSHORE WIND PROJECT

Note: NPV of GDP impact shows the net present value (3% real discount rate) of GDP impacts from 2020 through 2040.



$1,200M O&M expenditure increases RI GDP by $300M (NPV)

$4,000M construction expenditure (31% in-state; $1,200M) adds $800M to RI GDP (NPV)

$800M Tariff Impact (vs assumed $30 REC) decreases RI GDP by $400M (NPV)

NVP of GDP Impact: +$700M
(Out-of-State: -$400M)

FIGURE 17: RHODE ISLAND GDP IMPACT OF OFFSHORE WIND TECHNOLOGY BOOKEND

Note: O&M and Tariff Impact continue until the off-shore wind plants shut down (or the contract terminates), but are not forecasted here beyond 2040, due to the challenges and uncertainties associated with projecting such distant periods. NPV is calculated for 2020-2040.

years, reflecting the overlapping construction periods of this assumed series of new offshore wind resources. Similarly, the effects of O&M expenditures and the tariff impacts phase in as the series of projects comes online through 2030. The solid line adds the three categories to show the net GDP impact of in-state offshore wind. Net economic benefits are positive through the construction periods and then dip to being moderately negative in later years, due to falling energy prices.

Here, we also show a second and lower dashed line to illustrate the potential Rhode Island GDP impact of a hypothetical out-of-state Offshore Wind Bookend. This would fill the renewable energy gap entirely with offshore wind that does not rely on a Rhode Island port, and does not source significant labor, equipment or material resources from Rhode Island. This out-of-state bookend includes only the effect of the Tariff Impact, and would lead to no economic impact via the Construction and O&M Expenditure categories.[64] This illustrates the potential difference to the Rhode Island economy between sourcing renewable resources from within the state vs. from outside the state.

We apply this approach to each of the four Technology Bookends to estimate their economic impacts. **FIGURE 18** shows the resulting GDP impacts for each (comparable employment impacts are also calculated and are presented in the Technical Support Document). For Offshore Wind and Wholesale Solar, values are shown for both in-state (solid line) and out-of-state (dashed line) versions of the Technology Bookends. The Land-Based Wind Bookend, because it is only an out-of-state resource, results in a present value GDP loss

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[64] In reality, any New England offshore wind project would likely utilize at least some Rhode Island resources, due to the state's location near the existing lease areas and the interconnected supply chains between Rhode Island and neighboring states. But different projects may have differing local content; this comparison makes the extreme assumption of no local content, to illustrate the potential range of local impacts. It is also possible that an offshore wind project could have more local Rhode Island content than is assumed in the typical sector allocations; this would increase the benefits for the state's economy through the Construction and/or O&M Expenditures.

Continued Renewable Additions Beyond 2030

This analysis shows the impacts of only those resources that are needed for Rhode Island alone to achieve 100% by 2030 – i.e., those online by 2030. The impacts of additional new renewables that will likely be required to stay at 100% as load grows beyond 2030 are not included here, nor are the impacts associated with resources built to meet the policy goals of other New England states.

While examining only the resources online by 2030 keeps the focus for now on how to achieve the specific 100% by 2030 goal, the impacts of subsequent renewable additions will certainly need to be considered in the future (projections become increasingly uncertain farther into the future, but the analyses here may help to structure how to think about them).

If electrification load grows significantly beyond 2030, as is expected, continued renewable additions will be needed to meet this increase, and construction and O&M expenditures and tariff impacts will all extend further in time. Over the longer term beyond 2030, there may be a more or less continuous stream of economic impacts arising from continued construction and operating expenditures and tariff impacts as additional new renewables are added to meet growing load, at least until electrification opportunities are saturated. Still farther into the future, the timing of this saturation might very roughly correspond to the end of life of the early rounds of significant renewable additions (around 2040, assuming engineering and economic lives of about 20 years). Under this potential timeline, by about the time the renewable generation portfolio is fully built out for Rhode Island, a second wave of renewable additions may be necessary to replace the first.

of $500 million, while the in-state Offshore Wind, Wholesale Solar and Retail Solar Bookends show positive economic benefits, ranging from +$600 million for Wholesale Solar to +$900 million for Retail Solar. Out-of-state Offshore Wind and Wholesale Solar have impacts similar to Land-Based Wind. Retail Solar, despite having higher cost and thus a larger negative contribution to GDP from the Tariff Impact, also has a higher positive effect from construction and operating expenditures. On net, the NPV impact of Retail Solar is similar to the other in-state resources.

This leads to many important observations regarding the economic impacts of the four candidate energy resources.

- Whether a resource is located in-state or out-of-state has a substantial influence on how it affects GDP and jobs. As discussed, in-state construction and O&M expenditures create a boost for Rhode Island GDP and employment that may not exist (at least not at the same scale) with an out-of-state resource. Figure 18 gives some guidance as to the potential magnitude of the effect for different technologies, though the actual impact will be specific to each individual project and how it obtains labor, equipment and materials from in-state or out-of-state sources.
- There is little land-based wind resource available within Rhode Island, relative to the scale of the 2030 gap, due to relatively poor wind resource potential in the state. It is illustrated here only as an out-of-state resource, and thus its economic impact for Rhode Island consists only of the tariff impact.[65] Retail solar, on the other hand, is considered only as an in-state resource since only in-state locations are eligible for the Rhode Island programs that support these resources.
- As seen in the previous section, retail solar has significantly higher above-market costs than the other three technologies, which are similar to one another. The impact of this higher cost is seen in Figure 18, where the tariff impact has a significantly larger negative GDP effect than other technologies. However, the much

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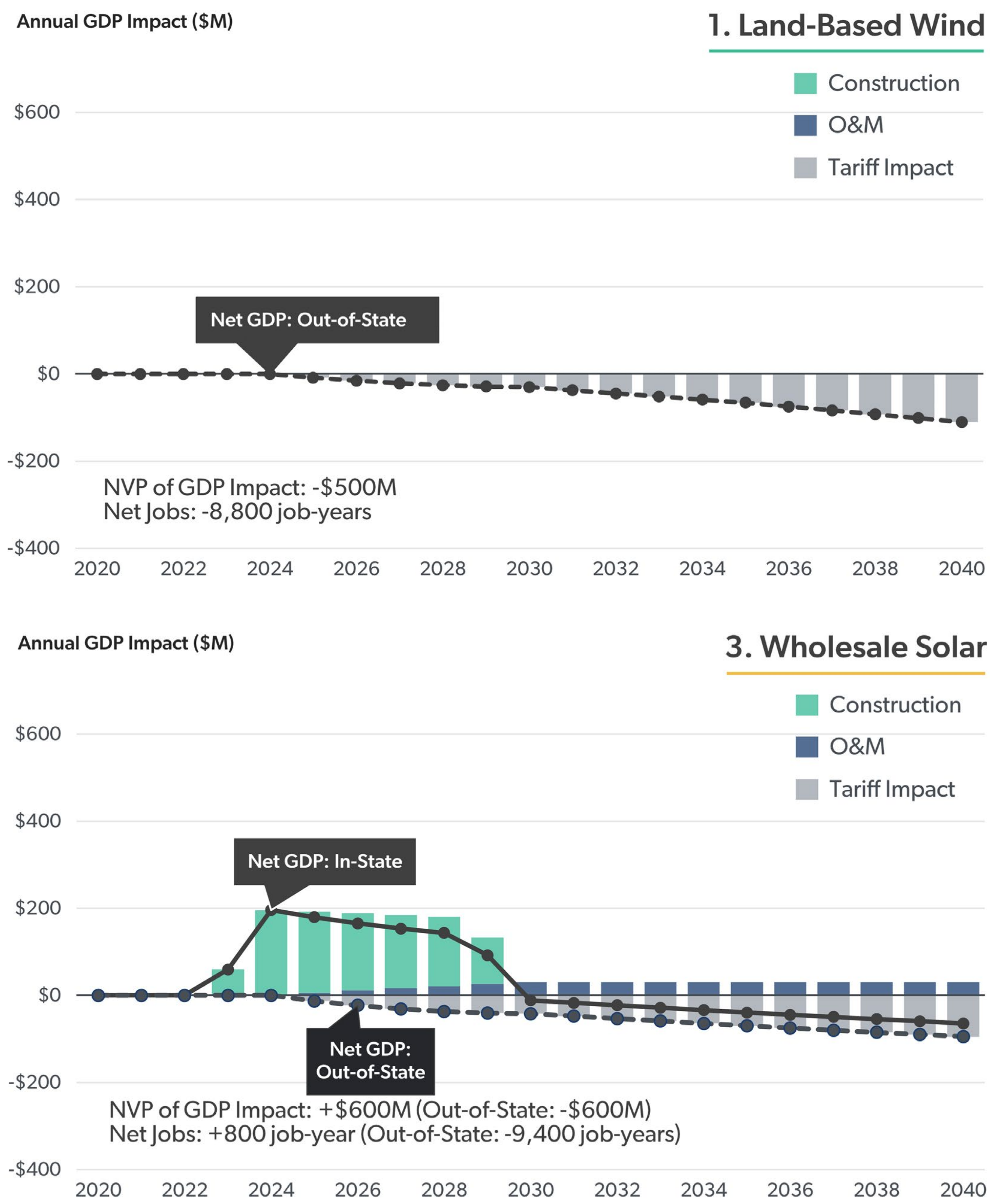
[65] There may be opportunities for some smaller Land-Based Wind projects within Rhode Island, and some may be attractive. Still, in-state Land-Based Wind cannot play a major role in filling the gap due to its limited availability.

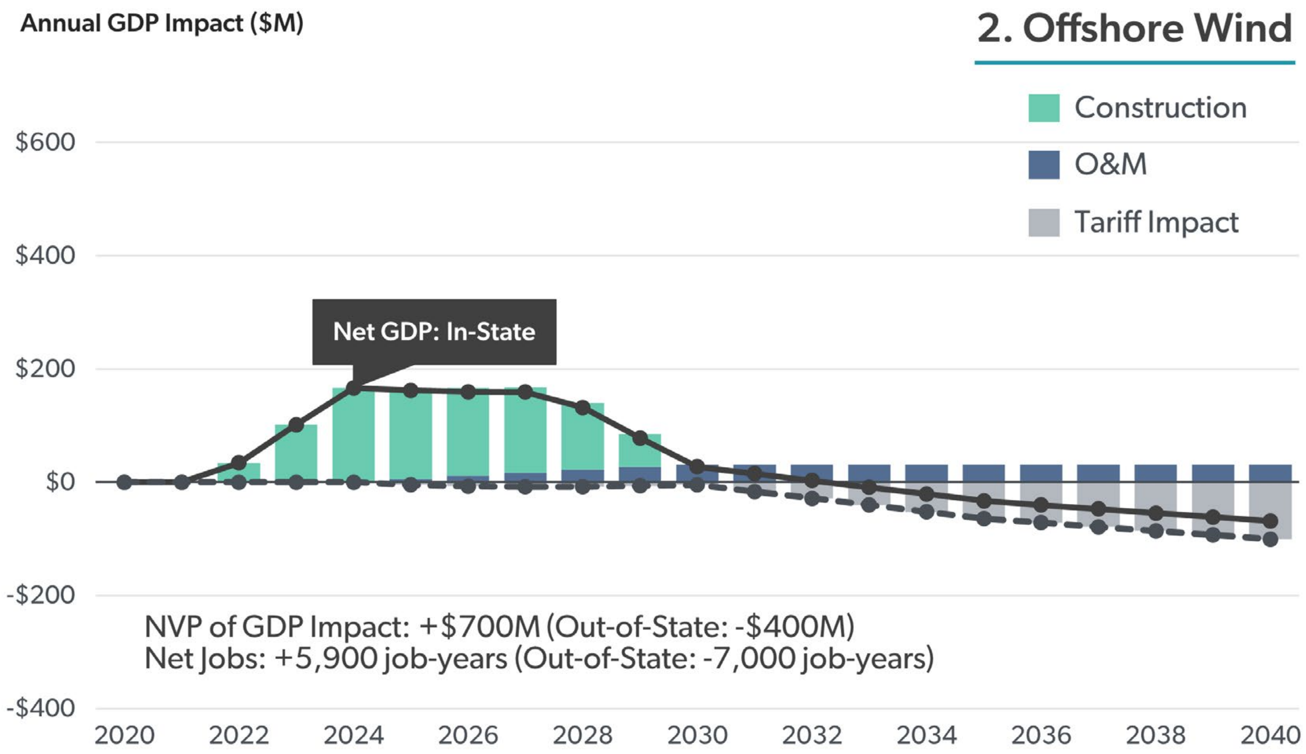


NVP of GDP Impact: -$500M
Net Jobs: -8,800 job-years

NVP of GDP Impact: +$600M (Out-of-State: -$600M)
Net Jobs: +800 job-year (Out-of-State: -9,400 job-years)

FIGURE 18: RHODE ISLAND GDP IMPACT OF TECHNOLOGY BOOKENDS

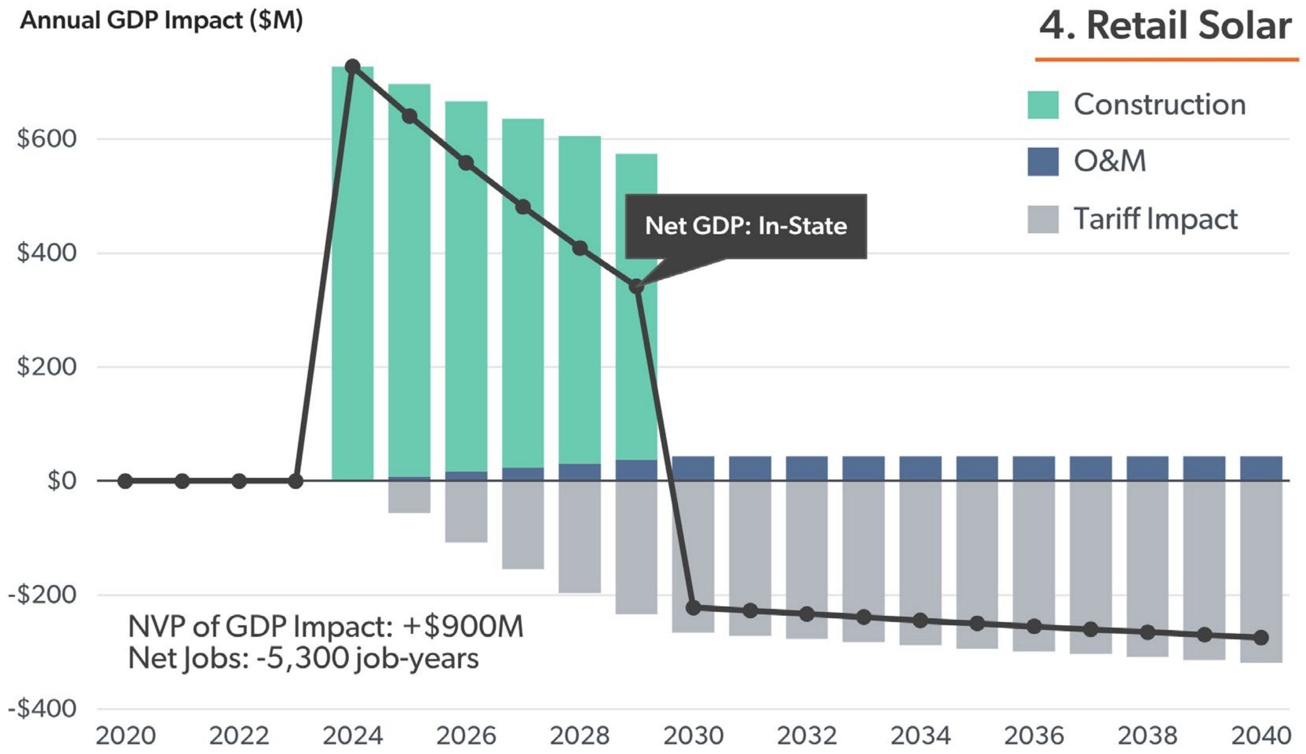
Note: NPV is calculated for 2020-2040.



2. Offshore Wind

Net GDP: In-State

NVP of GDP Impact: +$700M (Out-of-State: -$400M)
Net Jobs: +5,900 job-years (Out-of-State: -7,000 job-years)



4. Retail Solar

Net GDP: In-State

NVP of GDP Impact: +$900M
Net Jobs: -5,300 job-years

larger positive in-state impact due to higher construction and O&M expenditures offsets much of the negative impacts of the higher costs of these distribution-level solar resources.

- Compared with wholesale solar, retail solar's higher cost means that total construction expenditures are higher, and in addition, a larger share of each construction dollar for retail solar enters the local Rhode Island economy. This is because the components that contribute the most to retail solar's higher cost also tend to be those that yield greater local economic impact – e.g., local labor and services rather than imported solar panels or wind turbines.

As we did with the analysis of above-market cost for each of the Technology Bookends, we also consider in these economic impact estimates due to the range in resource acquisition costs uncertainty. Because the economic impact for each Technology Bookend is assessed relative to the cost of purchasing RECs from the market, we also look at the impact of different assumed REC prices. **FIGURE 19** illustrates how these uncertainties can be displayed, using the Offshore Wind Bookend as an example. The upper panel shows the range of GDP impacts across the range of resource acquisition costs considered above, relative to the Base $30 REC Cost. The solid bar for in-state offshore wind shows that at the Base Resource Cost, the NPV of GDP impacts is $700 million, as seen in Figures 17 and 18 above. At High Resource Cost, the Construction Expenditure provides a somewhat bigger GDP boost, but the Tariff Impact causes an even larger negative GDP change such that the net GDP impact falls to +$90 million. At a Low Resource Cost, the opposite happens, with the decreased Tariff Impact more than offsetting the smaller Construction Expenditure, leading the net GDP impact to rise to about $1,000 million. The lower, outlined bar indicates the out-of-state version of this Bookend. Because this does not include the positive impact of in-state Construction or O&M, the overall GDP impact is lower at any level of Resource Cost, and the effect becomes more extreme at High Resource Cost.

The second uncertainty, illustrated in the bottom panel of Figure 19, shows how changing the reference REC price affects the relative GDP impact. The middle bars in each group of three corresponds to the $30/MWh REC price shown in the upper panel. The lower bar corresponds to a lower REC price of $15/MWh, which increases the relative costs of the Offshore Wind Bookend, pushing GDP downward. A higher $45/MWh market REC price (upper bar) has the opposite effect. Relative to this higher reference price, the same Bookend saves ratepayers money, causing a boost to GDP and shifting the bar upward. Thus in the bottom panel of Figure 18, the length of any bar shows the range of GDP impact based on the uncertainty in Resource Cost at a given REC price reference, with each of the three bars using a different REC price as the reference point. As before, the out-of-state version (outlined bars, shifted to the left but overlapping) has lower GDP impact at any level of Resource Cost, and the effect is exaggerated at High Resource Cost.

These same uncertainty ranges are applied to all of the Technology Bookends in **FIGURE 20**, showing both the Resource Cost uncertainty and the range of different REC prices used as a reference, and also showing in-state and out-of-state versions where appropriate.[66] This high-level summary of the economic impacts of each candidate renewable energy resources enables some additional observations.

- Achieving 100% renewable electricity by 2030 by targeting in-state offshore wind or solar resources results in net positive economic benefits for Rhode Island, compared to purchasing market RECs, across most assumptions on resource costs and REC prices. Further, the GDP impact of in-state technologies falls less quickly at higher resource costs, since the negative effects of higher ratepayer costs are partly offset by the positive economic benefits of higher in-state construction and O&M expenditures.

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[66] For the purposes of this report, "in-state offshore wind" refers to offshore wind projects located in adjacent federal waters that are supported, in part, by Rhode Island ports and labor pools. Conversely, "out-of-state offshore wind" refers to projects that are entirely sourced from ports located outside of Rhode Island.

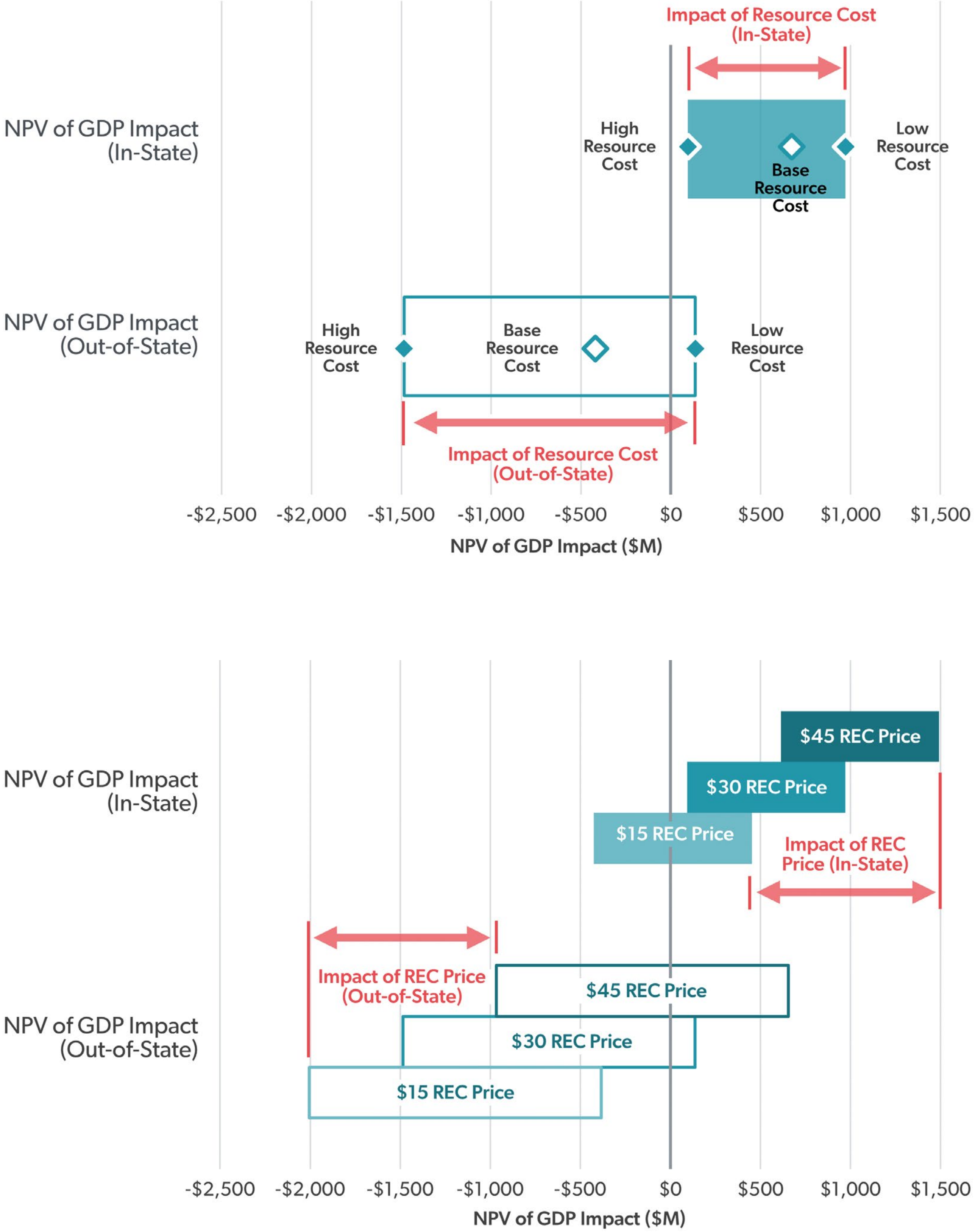

FIGURE 19: ILLUSTRATION OF UNCERTAINTIES IN GDP IMPACT (OFFSHORE WIND TECHNOLOGY BOOKEND)

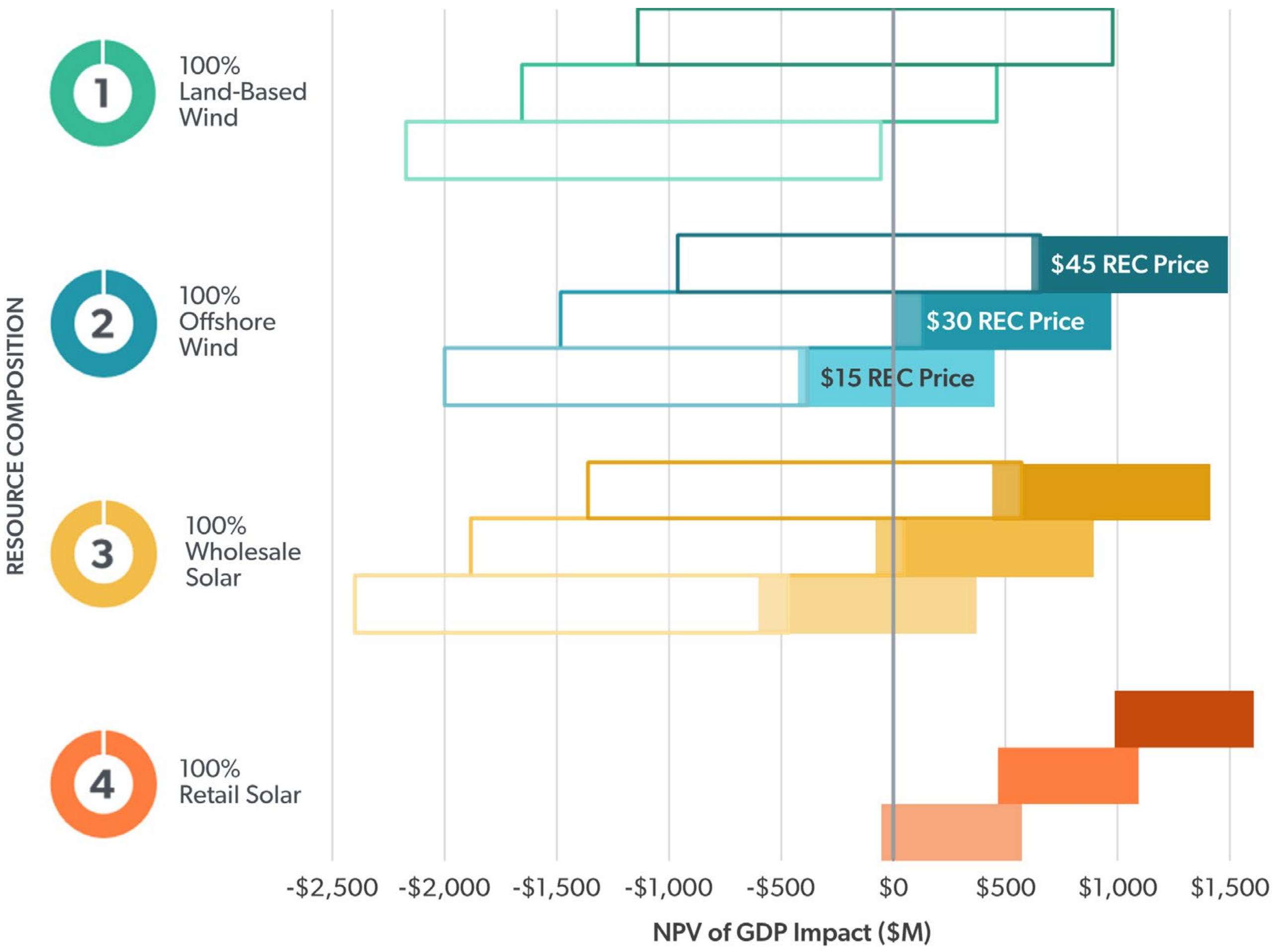

FIGURE 20: NPV OF RHODE ISLAND GDP IMPACT (2020–2040) WITH UNCERTAINTIES; BOOKENDS
(REFLECTING RESOURCE COST & REC PRICE UNCERTAINTY)

Note: In-state versions of Technology Bookends are illustrated by solid bars, and out-of-state versions by outlined bars.

- Purchasing out-of-state land-based wind, offshore wind, or wholesale solar resources may result in negative economic impacts. Only when the out-of-state resource is less costly than purchasing market energy and RECs (i.e., when resource costs are low and market REC prices are high) does procuring mostly out-of-state resources result in positive economic impacts.
- The economic benefits of achieving 100% renewable electricity by 2030 is significantly lower, and is more uncertain, when relying on out-of-state resources due to the lack of local economic benefits from construction and O&M.
- Comparing the in-state technologies, the ranges of economic benefits are similar. Since the resource costs are not necessarily related across technologies (cost of one technology could be at the high end of its range while another is at its low end), none of these technologies has a clear advantage in terms of overall economic impact (project-to-project cost variability can also contribute to this). Although retail solar has materially higher costs, its overall economic impact may be as good as (or better than) the utility-scale technologies.
- Rhode Island can increase the economic benefits associated with the 100% renewable electricity goal by developing programs and policies that procure in-state resources at the lowest reasonable cost to ratepayers.

Distribution of Economic Impacts

It is important to note that the positive and negative components of economic impacts (e.g., the positive impacts of Construction and O&M Expenditures; the potentially negative Tariff Impacts) may be unevenly distributed, and will not necessarily accrue to the same populations. Many of the jobs and much of the GDP benefit will occur in clean energy sectors, though of course this economic activity will have some positive spillover benefits into other sectors and the Rhode Island economy in general. But all ratepayers – residential, commercial and industrial – will bear any above-market costs. While these above-market costs may be modest or nonexistent (relative to REC purchases) for the utility-scale technologies, the above-market costs of retail solar may be material. This should be accounted for in evaluating the options for reaching 100% renewables – particularly in understanding how this may affect the equitable distribution of costs and benefits resulting from the strategies Rhode Island chooses.

Analysis of the net economic impacts of each resource tells a different story from the ratepayer costs assessed previously. The technology with the lowest above-market cost is not (necessarily) the one that offers the best economic impacts in terms of local GDP and employment. While above-market costs are associated with significant uncertainty, the ratepayer cost analyses showed that the three utility-scale technologies – land-based wind, offshore wind, and wholesale solar – have similar cost ranges that may be broadly comparable to the cost of purchasing RECs. But costs for retail solar are materially higher, and since the utility-scale technologies will likely be primary factors driving regional REC prices (at least over the long term), retail solar will very likely be more costly than either buying RECs or acquiring utility-scale resources.

However, in terms of the impact on GDP and employment, the positive economic impact of in-state construction expenditures can help to offset the negative impact of higher costs. This is a particularly important factor for retail solar, since it is likely to impose materially higher above-market costs for ratepayers than utility-scale technologies or REC purchases. But it would also have the highest positive economic impacts from construction and operation. This is partly because higher costs correspond to higher in-state expenditures, and also because retail solar has a greater local impact for each dollar expended (a higher share of its costs actually enter the local economy). This offsetting positive impact on GDP and employment means that retail solar may ultimately have similar net economic impacts across the state as in-state offshore wind or wholesale solar, though it would also result in more significant shifts among sectors of the Rhode Island economy. (See Sidebar regarding the distribution of economic impacts.)

The overall economic impact of out-of-state resources is much more dependent on the realized resource cost because they lack the offsetting local economic benefits of in-state expenditures. In Figure 19, the GDP impact of the (out-of-state) Land-Based Wind Bookend is lower at any level of resource cost than that of the in-state Offshore Wind or Wholesale Solar Bookends, despite that the above-market costs are quite similar. This is equally true of out-of-state versions of the Offshore Wind or Wholesale Solar Bookends. Importantly, this also makes the GDP impact much more sensitive to variations in the realized resource cost. For out-of-state technologies, the GDP impact falls sharply at higher resource costs (the bars have a wider range). In contrast, for in-state resources like Offshore Wind and Wholesale Solar, at higher resource costs, the correspondingly higher in-state expenditures partially offset the greater negative Tariff Impact, leading to a narrower (and higher) range of GDP impacts. While higher cost is worse on balance, the effect is partly mitigated. In order for an out-of-state resource to overcome the positive economic impact advantage of in-state resources, it would need a substantial cost advantage. There is little to indicate that out-of-state resources would be materially cheaper in general, though this could be true for some specific projects.

III.D Technology Portfolios: Above-Market Costs and Economic Impacts

The four Technology Bookends considered above are helpful for considering the relative strengths and weaknesses of each of the primary technologies that are available to fill the 2030 renewable energy gap. However, it is doubtful that the entire gap will be filled with a single technology; Rhode Island will likely use a mix of these technologies to reach 100% renewables. We created several representative Technology Portfolios to analyze the ratepayer above-market costs and economic impacts of more realistic technology mixes. Each consists of an alternative combination of the various technologies, as described in **FIGURE 21**.

These Portfolios, which all achieve 100% renewable electricity by 2030, are structured to balance three pillars: resource diversity, affordability, and local economic development. They show incremental offshore wind procurement of up to 600 MW, reflecting Rhode Island's recently announced RFP and alternative balances of wholesale and retail solar. Offshore wind is considered in increments of 600 MW in Portfolios 5 and 6, 400 MW in Portfolios 7 and 8, or 200 MW in Portfolio 9 – all assumed to come online in 2027. These amounts of offshore wind would contribute 2,700 GWh, 1,800 GWh, or 900 GWh annually, corresponding to roughly 60%, 40%, or 20% of the remaining 2030 renewable energy gap. Combinations of wholesale and/or retail solar provide the additional renewable energy to achieve 100% in 2030. The solar technologies are assumed to come online in equal increments over the period 2025-2030. One additional portfolio, Portfolio 10, involves no further offshore wind beyond Block Island and Revolution Wind; it consists mostly of wholesale and retail solar, plus 100 MW of land-based wind. Of course, many other resource combinations are possible; this set of Portfolios is intended to be representative, not comprehensive, and can offer a number of insights.

FIGURE 22 calculates the ratepayer above-market costs for each of these Portfolios, similar to Figure 13 above, and includes 100% Market REC Purchases and the four Technology Bookends for reference. The six Technology Portfolios just defined are arranged top to bottom in order of decreasing offshore wind and increasing retail solar content. The figure shows that the net present value of above-market costs rise from $2,000 million in Portfolio 5 to $3,000 million for Portfolio 10 (assuming Base Resource Costs), and the cost uncertainty also increases. Because retail solar has higher above-market costs and the costs of the other technologies are similar, the overall above-market cost of each portfolio is closely related to its retail solar content.

As discussed above, the cost uncertainty is primarily driven by the range of resource acquisition costs and results in significant overlap across portfolios. Because the Technology Portfolios consist of many of the same technologies, their costs are not necessarily independent of one another. For example, although Portfolios 9 and 10 each have above-market cost ranges of about $2,000 to $5,000 million, it is unlikely that one would be significantly more or less costly than the other because they have generally similar composition.

FIGURE 23 shows the GDP impact for each of the Portfolios. As was seen in Figure 20, the GDP impacts are similar across the in-state renewable energy resources, with Retail Solar having a slightly higher positive GDP effect. When these resources are combined into Portfolios, these relationships still hold. While there may be a slight potential increase in GDP benefits as the resource mix shifts from in-state offshore wind to in-state Retail Solar, the uncertainty in the impacts is much greater than the differences across the Technology Portfolios. As was illustrated for the Bookends, a second set of bars shown in outline represents an alternative version of the Portfolios that consists entirely of out-of-state resources. These out-of-state portfolios result in significantly lower GDP, and the effect is more pronounced at High Resource Costs. Of course, a Portfolio consisting of a mix of in-state and out-of-state resources, or a different mix of the technologies, would

	Description	Land-Based Wind	Offshore Wind	Wholesale Solar	Retail Solar
5	Max OSW, plus Wholesale Solar	--	600 MW (2,750 GWh)	Fill remaining gap (1,850 GWh)	--
6	Max OSW, RE Programs Maintained	--	600 MW (2,750 GWh)	Fill 50% of remaining gap (925 GWh)	Fill 50% of remaining gap (925 GWh)
7	Robust OSW, RE Programs Maintained	--	400 MW (1,825 GWh)	Fill 66% of remaining gap (1,850 GWh)	Fill 33% of remaining gap (925 GWh)
8	Robust OSW, RE Programs Doubled	--	400 MW (1,825 GWh)	Fill 33% of remaining gap (925 GWh)	Fill 66% of remaining gap (1,850 GWh)
9	Incremental OSW, RE Programs Doubled	--	200 MW (900 GWh)	Fill 50% of remaining gap (1,850 GWh)	Fill 50% of remaining gap (1,850 GWh)
10	Solar Heavy, Some LBW, No New OSW	100 MW (300GWh)	--	Fill ~60% of remaining gap (2,600 GWh)	Fill ~40% of remaining gap (1,700 GWh)

FIGURE 21: TECHNOLOGY PORTFOLIOS – DEFINITIONS

result in economic impacts that are a comparable mix of the values illustrated here.

As was seen with the Bookends, the two metrics tell different stories for the Portfolios as well. Although Portfolios with higher amounts of retail solar do have higher above-market costs, their GDP impact is generally comparable to the other Portfolios, and perhaps slightly higher, because of the offsetting positive economic impact of the in-state Construction Expenditures. While land-based wind lacks these local benefits, its impact is not particularly apparent in the Portfolios considered here, since only Portfolio 10 contains any land-based wind, and it has only as a small portion. But as reflected in the entirely out-of-state versions of these portfolios (outlined bars), having a significant share of out-of-state resources in any of these portfolios would depress the local GDP (and employment) impact considerably.

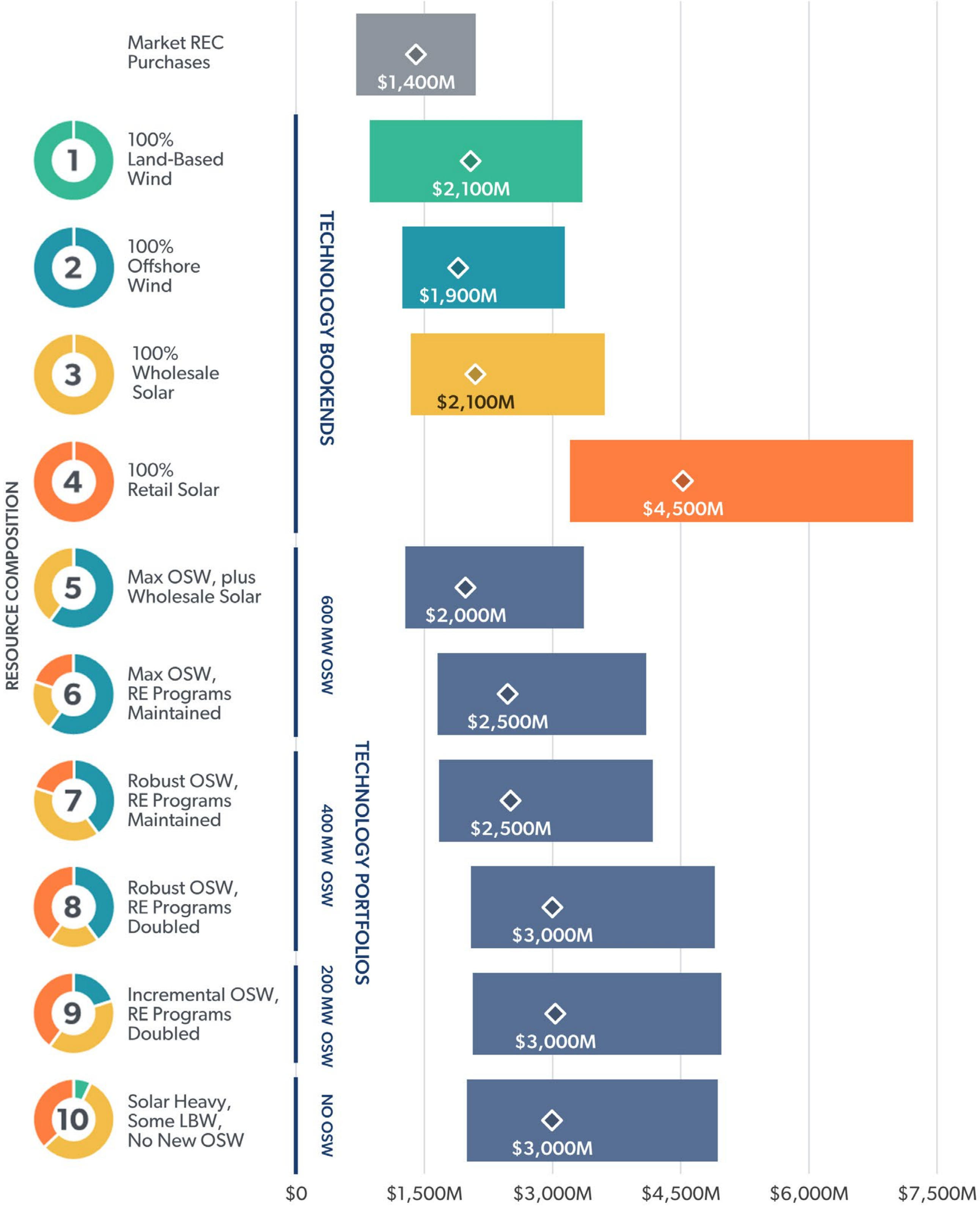

FIGURE 22: NPV OF ABOVE-MARKET COSTS (2020–2040) OF ACHIEVING 100% RENEWABLES; BOOKENDS AND PORTFOLIOS (NET OF ENERGY AND CAPACITY REVENUES, NOT REC REVENUES)

Note: Ratepayer costs reflect the total incremental costs of achieving 100% net of energy and capacity revenues.

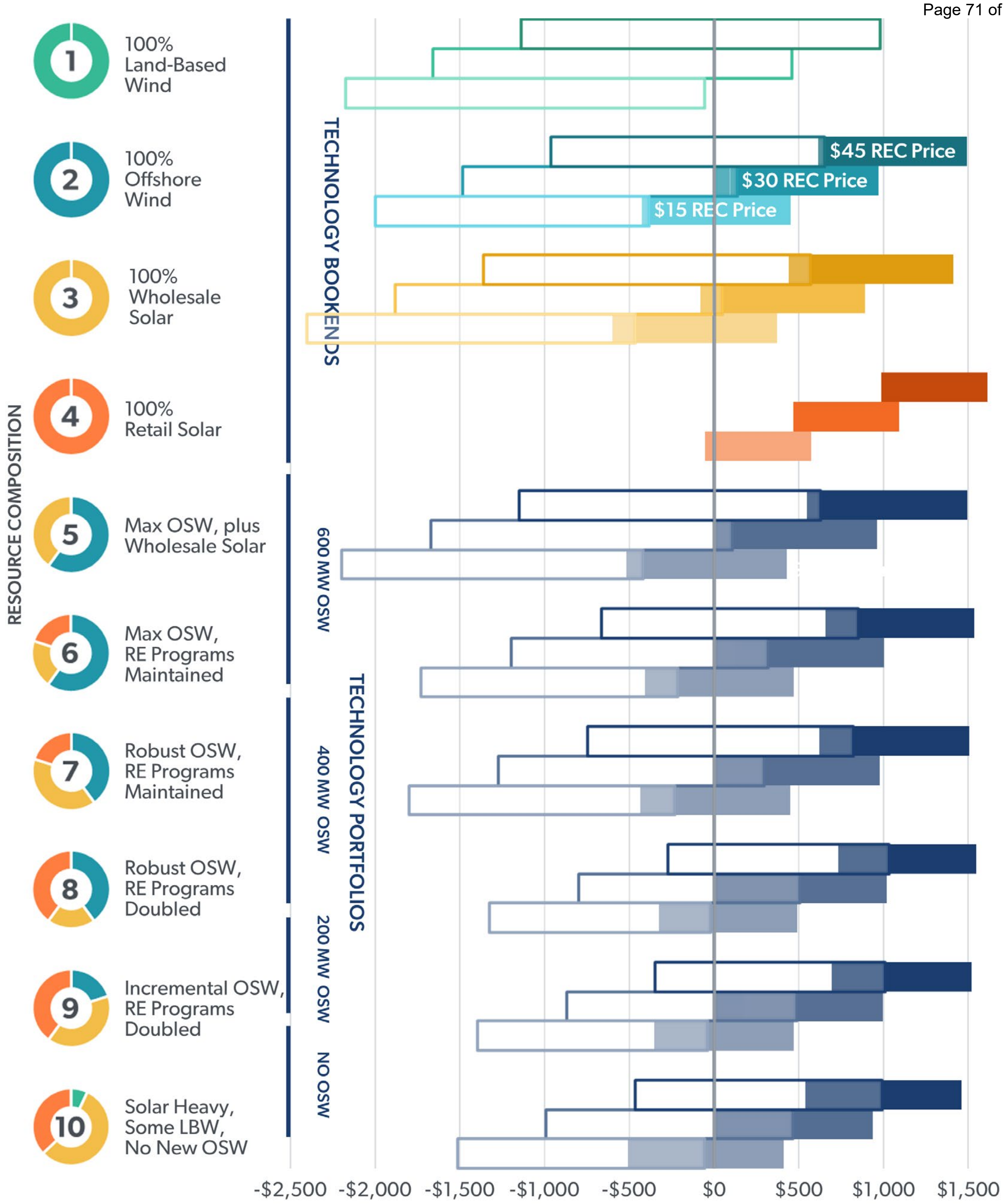

FIGURE 23: NPV OF RHODE ISLAND GDP IMPACT (2020–2040) WITH UNCERTAINTIES; BOOKENDS AND PORTFOLIOS (REFLECTING RESOURCE COST & REC PRICE UNCERTAINTY)

Note: In-state versions of Bookends and Portfolios are illustrated by solid bars (though land-based wind is out-of-state, even within an in-state portfolio). Out-of-state versions of Bookends and Portfolios are illustrated by outlined bars (though retail solar is always in-state, even within an out-of-state portfolio).

III.E Summary of Analytic Insights

We summarize here the key insights from the analytic portion of the study, regarding the renewable gap to 100%, the ratepayer costs and the economic impacts of achieving 100% renewable electricity by 2030.

- Rhode Island's goal of 100% renewable electricity by 2030 is achievable. Renewable resources are available within Rhode Island and in surrounding areas to support this goal.
- Achieving 100% renewable electricity by 2030 will not be costless. It will require ratepayer support through bill charges to support investments that drive long-term energy, economic, and environmental benefits. In the near term, renewable electricity will cost more than fossil-fired generation (energy prices do not cover the full environmental costs of current fossil energy sources), and utility bills will be higher regardless of the composition of the ultimate portfolio of renewable resources. But net economic and energy benefits and costs will be determined by how that portfolio is shaped over time.
- Rhode Island should increase its Renewable Energy Standard to 100% renewable electricity by 2030. With changes, existing REC structures, tracking mechanisms and markets will allow Rhode Island to implement the 100% goal seamlessly, track its progress, and accommodate uncertainty and variability in electricity demand and renewable generation.
- Rhode Island should limit the extent to which it relies on short-term REC purchases to meet its 100% renewable goal. This will ensure that Rhode Island's actions truly achieve incremental GHG reductions, and will limit the customer cost impact of potentially volatile REC prices.
- Rhode Island's current renewable energy portfolio contains a mix of local resources and large-scale procurements. Additional capacity of similar resource types is likely to be necessary to achieve 100%, though the mix of resources may shift with evolving resource costs and the necessary infrastructure buildout.
- All renewable energy resource types will require planning and investment to build out the necessary infrastructure to achieve 100% cost-effectively. This includes the local distribution system, the onshore transmission system, and offshore transmission facilities, as well as the renewable generation itself.
- Different renewable resource portfolios will require different (and as yet unknown) distribution and transmission grid investments, and integrated planning may support cost-efficient outcomes. This effort will take significant time, collaboration, and upfront investment. Key questions will involve who determines which facilities are developed and how costs should be recovered; this is especially true for in-state offshore wind and solar resources. Utility-scale offshore wind, land-based wind, and solar resources are likely to be the lowest costs to ratepayers. However, each of these resources types present varying levels of in-state economic development and job growth potential. Available market data and cost projections also show significant and overlapping cost uncertainties for each.
- Distributed solar resources have significantly higher above-market costs; they can also result in significant shifts between ratepayers if acquired through net metering programs
- Rhode Island can identify the lowest cost resources by proactively planning the system upgrades necessary to achieve 100% and procuring renewable energy resources through competitive procurements and programs. Participating in multi-state solicitations may make it possible for Rhode Island to access the economies of scale of larger projects.
- Rhode Island can reduce ratepayer costs and risks by collaborating with other New England states to update the design of regional electricity markets to account for the full value of renewable energy resources to the system.
- In-state renewable energy resources, including offshore wind in adjacent Federal waters and higher cost retail solar, provide material local economic benefits relative to out-of-state resources and/or market purchases of RECs.
- The higher ratepayer costs of retail solar are partially offset by greater local economic benefits, leading to similar impacts

on overall state GDP as in-state utility-scale resources. However, the GDP benefits and costs do not accrue to the same populations; retail solar will result in greater shifts of costs and benefits within the Rhode Island economy.

- For the longer term, Rhode Island should consider acquiring a renewable portfolio that is a reasonable match for its hourly load profile. This will contribute to achieving the proper long-term balance across the region, and will reduce energy price risk and the costs of balancing supply and demand for Rhode Island ratepayers. With anticipated demand shapes, a portfolio of mostly wind with up to about 30% solar offers a reasonable hourly match, which is consistent with the current offshore wind RFP. This will become increasingly important as the rest of New England also moves toward higher renewable energy shares.
- To achieve and maintain 100% renewable electricity beyond 2030, policy, programmatic and technical (e.g. storage, demand management) solutions may need to evolve, as the regional penetration of clean energy resources accelerates and increasingly-challenging grid impacts emerge. There will likely be significant increases in the overall amount of energy needed to meet new electrification loads from the transportation and heating sectors, mostly beyond 2030.

IV. Recommendations for Achieving 100% Renewable Electricity by 2030

In this section, we describe a set of recommendations and action steps for 2021 and beyond to advance Rhode Island toward a 100% renewable electricity future.

These recommendations were developed primarily by the Office of Energy Resources and consultants at The Brattle Group, and informed by Rhode Island stakeholders (individuals and organizations) who submitted public comment and/or attended Public Technical Workshops and Community Listening Sessions.

Importantly, the following recommendations are grounded in the other three main components of this project – analysis, guiding principles, and public engagement. Insights gained from the analysis not only illustrate that getting to 100% renewable electricity by 2030 is achievable but highlight important tradeoffs between the paths we can take to get there. Our guiding principles provide a foundation for how we assess these tradeoffs and act as guiderails for resulting approaches to programs and policies. Lastly, public engagement throughout this project helped identify stakeholder priorities, which informed our recommendations

Policy and Programmatic Recommendations

Study insights inform three categories of recommendations:

POLICY

Recommendations for defining, achieving, and procuring 100% renewable electricity.

PLANNING & ENABLING

Recommendations on ways to reduce risk, increase flexibility, and optimize renewable energy integration.

EQUITY

Recommendations on ways to foster equitable outcomes developed in partnership with frontline communities.

and will help ensure all Rhode Islanders participate in our clean energy transition.

We categorize the recommendations into three segments: Policy, Planning & Enabling, and Equity. Equity is set aside as its own category in order to bring salience to this important topic. However, we assure readers that equity is also integrated into each of the Policy and Planning & Enabling recommendations. These recommendations should be considered in tandem with the findings presented earlier in this report; together, the analysis, findings, and recommendations chart a path to achieve 100% renewable electricity by 2030, while attempting to balance consumer costs, stakeholder priorities, and principled objectives. Finally, we note that achieving the outcomes resulting from the following recommendations is contingent on a number of external factors including, for example, the due diligence of legal, statutory, and regulatory review and their associated processes.

IV.A Policy Recommendations

Policy recommendations are intended to support defining, achieving, and procuring 100% renewable electricity. The first two recommendations entail legislative priorities: increasing the Renewable Energy Standard to 100% by 2030 and extending statutory authorization for Rhode Island's nation-leading cost-effective energy efficiency programs, called Least-Cost Procurement. The third recommendation is programmatic, and suggests continued support of local distributed renewable resources with cost-competitive, utility-scale renewable resources. This reflects the importance of balancing energy affordability and reliability with achievement of other policy objectives, such as growing local clean energy jobs and attracting clean investment across the Rhode Island economy.

Renewable Energy Standard

Key Concept: Advance a 100% Renewable Energy Standard

The Renewable Energy Standard (RES) requires retail load serving entities (e.g. National Grid and third-party competitive electricity supply providers) to meet an increasing share of their annual electricity deliveries with renewable energy resources.[1] Currently, Rhode Island's RES sets a statewide target of meeting 38.5% of electricity deliveries with renewables by 2035.[2] Eligible renewable energy resources include solar, wind, wave, geothermal, small hydropower, biomass and fuel cells. Rhode Island's Public Utilities Commission (PUC) is statutorily responsible for overseeing RES compliance on an annual basis.[3]

RES compliance does not involve the physical procurement of power produced by renewable energy facilities. Instead, electricity providers meet their requirements by purchasing renewable energy certificates (RECs). As explained above, eligible renewable energy resources generate RECs when they produce electricity that is delivered to the New England power system. One REC equals one MWh of qualified renewable generation provided to the electric grid for delivery to end use consumers. The buying and selling of RECs by renewable energy resources, traders, and obligated entities results in a market for RECs that allows obligated parties to cost effectively procure sufficient RECs to cover their obligations. The RES provides a framework that is flexible to accommodate the uncertainty in future renewable generation and electricity demand as it provides an available mechanism to true up inevitable short-term deviations from the renewable energy target.

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[1] Rhode Island's RES is set forth in RIGL 39-26. Other states have a similar statute called the Renewable Portfolio Standard (RPS) that is implemented in the same manner and achieves equivalent outcomes.

[2] Currently, the RES in 2020 is set to 16 percent, and escalates by 1.5 percent annually until 2035.

[3] See http://www.ripuc.ri.gov/utilityinfo/res.html for more information.

Policy Recommendations

Policy is needed to establish a strong, statewide framework and reach our goals in ways that align with our foundational principles

We must ensure we meet our clean energy goals by advancing a **100% Renewable Energy Standard**.

Continued efforts to decrease energy consumption of **Least-Cost Procurement and Nation-Leading Energy Efficiency Programs**.

Maintaining continued support for in-state development, while supporting **programmatic evolution** to deliver more affordable and sustainable outcomes.

RES compliance can also be achieved by making alternative compliance payments (ACPs) to the Rhode Island Commerce Corporation's (Commerce RI) Renewable Energy Fund (REF). The ACP functions as a price ceiling, allowing electricity providers to comply with the RES mandate if REC shortages occur. Alternative compliance payment revenues deposited into the REF are then used to support state programs that increase the supply of renewable resources on the grid, which can help ameliorate tightening of the REC market in the future.

We propose amending the state's RES to require 100% renewable electricity by 2030, which would make Rhode Island the first state in the nation to achieve this ambitious, but achievable goal. In doing so, we can also leverage existing accounting practices (e.g. NEPOOL GIS and annual regulatory reports) to transparently account for compliance. In designing a 100% by 2030 RES, we should also seek methods by which Rhode Island might retain, for statewide RES compliance, all of the RECs procured through existing policy and programmatic channels (e.g. through long-term contracts and the Renewable Energy Growth Program), as well as those RECs produced from ratepayer investment in net metered projects. All of these RECs, which are ultimately paid for by electric distribution ratepayers, should be retired on their behalf to support compliance with the 100% RES goal.

Relying on RES to ensure we meet the 100% renewable by 2030 goal is consistent with the guiding policy implementation principle to *build on RI's existing renewable energy mechanisms*. Because the RES is also a market-based mechanism that allows obligated entities to procure renewable energy at market-driven, competitive prices, using the RES also aligns with the guiding economic principle to *pursue cost-effective solutions*. Lastly, a statutory mandate to achieve 100% renewable electricity by 2030 would propel Rhode Island to leading the nation with the fastest pace of electric sector decarbonization, and would advance theguiding principle to *exemplify climate leadership.*

There are several additional considerations related to the RES.

- First, the RES – in isolation – is unlikely to drive sufficient investment in incremental renewable energy generation. It should be paired with programs and policies to ensure there will be sufficient renewable energy generation available to meet the 100% goal. Nonetheless, the RES is a valuable tool by helping developers monetize the environmental attributes (represented by RECs) associated with carbon-free generation. Coupled with other policy and programmatic support, a 100% RES will contribute to *creating incremental power sector decarbonization.*

- Second, the RES is blind to RECs created by renewable energy systems that are "behind-the-meter."[4] Behind-the-meter RECs can result in double counting: reducing REC requirements for on-site demand and also covering the REC requirements for another customer. As we approach 2030, we will need to address these considerations through programmatic adjustments to ensure in-state renewable energy generation is properly counted towards Rhode Island's 100% goal.
- Third, in time, additional mechanisms will likely be needed to better match the timing of renewable energy generation with real-time demand.[5] Analytical insights suggest this consideration is not critical to address until the regional electric grid approaches a higher penetration of renewable electricity. Rhode Island should monitor grid conditions within the state, renewable energy policies and electricity market conditions across the region, and the efficacy of programs and policies across the nation.
- Finally, a 100% RES should remain in effect beyond 2030 and match shifts in energy demand – particularly as other sectors of the economy (e.g. heating, transportation) increasingly electrify. This will help ensure that these new, electrified solutions are being powered by carbon-free resources. This is responsive to the guiding policy implementation principle that we *ensure solutions are robust and sustainable past 2030.*

Energy Efficiency

Key Concept: Extend Least-Cost Procurement of energy efficiency and demand response

Energy efficiency programs cost-effectively reduce energy consumption via efficiency and conservation measures, and can shift the timing of energy consumption via demand response programs.[6] Rhode Island has consistently ranked among the top states in the nation for energy efficiency policies and programs, and Rhode Island's largest electric distribution utility consistently ranks among the best in the country for its energy efficiency programs.[7]

Since 2007, energy efficiency programs have saved over 10 million MWh of electricity at a cost lower than that of procuring traditional electric supply, leading to substantial energy cost savings for ratepayers and reducing exposure to price volatility.[8] Energy efficiency programs also support local businesses, investment, and job creation; in fact, energy efficiency programs support approximately two-thirds of Rhode Island's clean energy jobs. Energy efficiency also supports improved building comfort and health, and numerous other societal values.[9]

The statute that enables Rhode Island's energy efficiency programs is called Least-Cost Procurement.[10] In 2006, the Rhode Island General Assembly passed legislation that established the Comprehensive Energy Conservation, Efficiency and Affordability Act. The Act created a groundbreaking mandate termed "Least-Cost Procurement"— a policy that requires Rhode Island electric

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[4] Behind-the-meter systems are electrically connected to a property's electric panel rather that tied directly to the electric grid.

[5] Examples of policy and programmatic mechanisms that may increase the generation and demand-side resources available during peak demand periods include energy market pricing reforms, a higher price on greenhouse gas emissions, a Clean Peak Standard, enhanced demand response, and targeted incentives for renewable-paired storage, among others.

[6] Common examples of energy efficiency measures include lighting upgrades, heating and cooling equipment enhancements, and insulation. Common residential demand response technologies include smart WiFi-enabled thermostats and battery storage.

[7] See: https://www.aceee.org/state-policy/scorecard

[8] http://rieermc.ri.gov/wp-content/uploads/2020/05/ngrid_4888-year-end-report-2019-puc-5-15-20.pdf

[9] For more information about energy efficiency program planning and implementation, please see www.rieermc.ri.gov.

[10] See: RIGL 39-1

and natural gas distribution companies to invest in all cost-effective energy efficiency before the acquisition of additional supply. This strategy is "least-cost" because energy-saving measures—such as higher-efficiency lighting, HVAC systems and appliances, insulation, and air sealing—in aggregate, cost approximately 4 to 6 cents per kWh over their lifetime while electric supply costs between 8 cents and 12 cents per kWh.[11]

We propose to extend Least-Cost Procurement of energy efficiency and demand response to at least 2030. Cost effective energy efficiency is the lowest-cost means of reducing energy costs, avoiding the need to serve the same level of energy demand with more costly resources, including renewable energy resources. Consistent with this policy recommendation, we have modeled various levels of continued energy efficiency savings in our analysis. All three cases analyzed assume continued implementation of energy efficiency measures through 2030. The Base Case and High Load Cases assume the continuation of similar efficiency programs and funding levels, which will result in continued efficiency improvements, but at a decreasing incremental rate as the most cost-effective efficiency opportunities become saturated. The Low Load Case assumes increased efficiency efforts that result in a continuation of near-term incremental energy efficiency savings through 2030.[12]

In the absence of continued efforts to expand energy efficiency measures, our analysis would underestimate the scale of renewable energy resources and investments needed to meet the 2030 renewable energy goal. *Foregoing energy savings through these programs would result in an additional 1,500 GWh of electricity demand in the Base Load Case in 2030 that would need to be served by renewable energy resources. This magnitude is roughly equivalent to 490 MW of land-based wind, 350 MW of offshore wind, 1,070 MW of wholesale solar, or 1,310 MW of retail solar; this would be associated with cost increases of $600 million to $1.45 billion to achieve 100% by 2030.*[13]

The current Least-Cost Procurement statute sunsets following the 2023 program year, and we propose extending this foundational clean energy strategy. An extension will help ensure that robust, innovative and cost-effective energy efficiency programs remain accessible to Rhode Island energy consumers, and support business and workforce stability. In extending the availability of our cost-effective energy efficiency programs, we advance all nine of the guiding principles.

The Balance of Wholesale and Retail Renewable Energy

Key Concept: Continue to support utility-scale renewable procurements and local renewable development that reflects evolving market conditions.

Rhode Island has a history of successful and impactful renewable energy programs. Current programs include net metering (with incentives available through the Renewable Energy Fund), the Renewable Energy Growth feed-in-tariff program, and Community Remote Net Metering (CRNM), which has helped create opportunities for customers unable to install solar on their homes to participate in community-based renewable energy resources. The Renewable Energy Fund, in addition to providing grant funding for both residential and commercial solar PV systems, has also helped support solar projects on preferred locations such as brownfields and carports. In addition, utility-scale procurements, such as the procurements of 400 MW from

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[11] See, for example, program costs and benefits of National Grid's 2019 Energy Efficiency Program: http://rieermc.ri.gov/wp-content/uploads/2020/05/ngrid_4888-year-end-report-2019-puc-5-15-20.pdf.

[12] The Base Load Case and High Load Case assume the incremental annual energy savings from efficiency measures decrease from 190 GWh in 2020 to 120 MWh in 2030. The Low Load Case assumes incremental energy savings continue at 190 GWh per year through 2030.

[13] The range of cost savings are the net present value of 2020 to 2040 costs based on the base resource acquisition cost assumptions for each of the Technology Bookend scenarios.

the Revolution Wind offshore wind project off the Rhode Island coast, and 50 MW from the Gravel Pit Solar project in Connecticut, are driving Rhode Island's renewable portfolio to a larger scale.

Rhode Island's clean energy laws and programs strive to achieve multiple policy objectives, including, but not limited to greenhouse gas emissions reductions and environmental sustainability, energy reliability, energy affordability, economic development, and job creation. These policy objectives are also reflected in the guiding principles. To achieve and sustain 100% renewable electricity while advancing broad-based policy objectives, Rhode Island will require both continued growth in local distributed generation resources and competitive procurement of large-scale renewable energy resources.

Our analysis shows that there is significant uncertainty in costs across all renewable energy technologies. Different utility-scale renewable resources have similar cost ranges, which are lower than distributed generation resources.[14] We also see that a mix of resources weighted toward wind energy will best match electricity demand profiles and reduce system balancing needs that are expected to increase beyond 2030. However, in-state solar energy resources, particularly retail solar, provide economic development benefits that should be weighed against resource costs and environmental impacts.

Our analysis also helps us set guideposts for further renewable energy procurement based on the current outlook for future electricity demand and technology-specific net benefits. It does not support a single centralized procurement plan that would limit the potential to capture the benefits of evolving market dynamics and competition across resource types. Rather, we propose a market-driven approach that allows for cross-technology competition where appropriate, in line with the guiding economic principle to *pursue cost-effective solutions*. Reaching 100% while managing potential cost increases in other components of utility bills necessitates that cost-effectiveness remain a priority across programs.

Each of Rhode Island's existing renewable energy procurement programs has unique traits, creating multiple pathways for developers and consumers to participate in the clean energy future. However, some of these programs – particularly those supporting local distributed generation – present significant challenges that Rhode Island must begin to address. Some of these challenges include:

- Examining ways to reduce/control distributed renewable energy costs for local consumers, including cost shifts across customer classes;
- Identifying cost effective approaches to building out the Rhode Island distribution system to increase capacity for distributed renewable energy resources (as well as increasing demand from electrification of other sectors);
- Developing sustainable siting practices for local distributed renewable energy to balance renewable development with environmental stewardship;
- Integration of storage, demand management and other technological solutions; and
- Achievement of more equitable outcomes for all Rhode Islanders through improved access, participation, and cost distribution.

OER supports continuation of the Renewable Energy Growth (REG) program and net metering (NM). However, further expansion should be contingent on identification and integration of measures to improve sustainability, affordability, and equity. These challenges warrant in-depth collaboration with a diverse set of stakeholders, including policymakers, regulators, industry, environmental advocates, consumer advocates, utilities, and community organizations. In 2021,

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[14] Note that we use the terms "utility-scale" and "wholesale" interchangeably here to refer to large-scale procurements of renewable energy, such as through the state's Long-Term Contracting statute (RIGL 39-26.1). In contrast, retail renewable energy and local distributed generation refer to projects that are generally smaller in scale, like rooftop solar, that are provided incentives through programs like REG, which offers a feed-in tariff, or net metering and associated incentives through the Renewable Energy Fund (https://commerceri.com/financing/renewable-energy-fund/).

we propose to commence a forum for stakeholder dialogue and consensus-building on the long-term costs and benefits of the state's net metering construct, as well as to consider other enhancements to reduce ratepayer costs and improve environmental sustainability and consumer equity, with recommendations due by the end of the year.

We also propose that the Renewable Energy Fund (REF) be extended by the General Assembly beyond its current 2022 sunset. OER and Commerce RI will continue to coordinate on identifying administrative and programmatic adjustments to the REF throughout 2021 that further renewable growth and clean energy innovation, and evolve the REF to address gaps in evolving market conditions, considering foundational principles. OER and Commerce have already begun this work by utilizing the REF framework to support renewables on brownfields, storage, and, soon, microgrid applications. The Clean Energy Internship program, co-managed by both OER and Commerce, should also continue beyond 2022.

Lastly, continued support of the burgeoning offshore wind industry will also be critical to the Rhode Island clean energy economy and a decarbonized future for the region. Governor Raimondo's October 2020 announcement calling for a competitive market procurement for up to 600 MW of newly-developed offshore wind energy is consistent with this recommendation.[15] As future large-scale renewable procurements advance, the state should also consider the timing of similar efforts across the region, which may unlock opportunities to benefit from greater economies of scale and further expansion of clean energy supply chain investments and job growth in Rhode Island and southern New England. This recommendation advances all nine of the guiding principles.

IV.B Planning and Enabling Recommendations

Planning and enabling recommendations are actions we propose to take to reduce risk, increase flexibility, and optimize renewable energy integration. Rhode Island's suite of planning and enabling recommendations encourages exploration, collaboration, and strategic planning. The first recommendation calls for a pilot collaboration among key stakeholders to marry policy objectives into grid planning with the aim of finding efficiencies. The second recommendation continues Rhode Island's efforts related to Power Sector Transformation, while a third calls for building out a strategic role for energy storage technologies and demand management. Finally, we recommend continued collaboration with the other New England states to improve regional wholesale markets and transmission planning processes to more effectively enable a largely-decarbonized electric grid.

Integrated Grid Planning

Key Concept: Optimize the electric grid through collaborative, integrated grid planning

The poles and wires that make up Rhode Island's electric grid must be carefully planned to ensure safe and reliable service to customers. Oversight from the Division of Public Utilities and Carriers and regulatory review from the Public Utilities Commission helps to ensure that grid investments are right-sized, right-timed, and appropriate to maintain service standards. Forecasts of electric load growth and in-depth technical understanding of grid assets allow distribution system planning engineers to propose strategic investments to serve load expected to materialize in near-term. This established and well-vetted approach to grid planning can and will continue to serve Rhode Islanders well.

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[15] A draft RFP is anticipated to be filed with state regulators in early 2021.

Planning and Enabling Recommendations

We need to advance innovative, integrated, and collaborative **planning** to **enable** interconnection of clean energy onto the grid while minimizing costs and optimizing land use.

Optimize the electric grid through collaborative, **integrated grid planning**.

Facilitate integration of distributed energy resources by advancing **Power Sector Transformation and Grid Modernization**.

Build out a strategic role for **energy storage** technologies

Continue **regional collaboration** on wholesale markets and interstate transmission.

Analytical insights show that interconnection costs of distributed solar resources have risen significantly and are likely to continue to do so without more advanced, dynamic grid planning. Increasing electrification demand will also require additional investments in the distribution system. Increased penetration of renewable energy resources, load growth from beneficial electrification, and competing policy pressures (e.g. related to land use) are three drivers of how and where the electric grid is built out.

We propose to consider these drivers over longer time horizons to better understand and plan for changing future system needs. Our goal is to explore how we transition from today's electric grid to the electric grid required to meet Rhode Island's long-term clean energy and GHG reduction goals. The current planning approach reacts to proposals for distributed energy resource deployment. Integrated grid planning could more proactively consider state policy objectives, municipal preferences, clean energy resource opportunities/needs, land use/siting, etc. Grid planning is multi-faceted, technical, and complex. There are no simple solutions that will substantially drive down costs or advance all policy objectives completely. However, more proactive and informed planning over longer horizons will likely lead to long-term grid optimization, efficiencies, and policy objectives. This recommendation does not advocate for immediate investments in grid infrastructure, but asks whether and how electric distribution utilities, state agencies, municipalities, and others might identify zones more favorable to renewable energy in light of competing policy interests, and remove barriers to distributed energy resource deployment.

We propose two potential areas of exploration. First, we propose to analyze transmission and distribution system needs for several 100% renewable electricity scenarios to identify potential grid challenges and development opportunities. We will identify the potential for anticipating system reliability needs and other system upgrades – whether project-specific or broader system upgrades – that might enable renewable energy growth, reduce development risks, balance environmental sustainability, and moderate long-term costs that consumers might otherwise bear. We will consider wide variations in load, renewable portfolios, and hosting capacity needs.

Specifically, we propose a collaborative effort with National Grid, state agencies, municipalities, and other key stakeholders to explore the potential for a more integrated approach to grid planning beginning in 2021. The objectives of this collaboration are to foster improved understanding of how short- and mid-term planning can and should account for longer-term dynamics, estimate long-term impacts to the grid from both distributed energy resources and load growth, and compare grid investments under reactive and proactive approaches. We seek to identify locations for distributed energy resources that could streamline development timelines, protect the state's most sensitive environments, and offer the potential to reduce long-term, system wide costs. Critical to this effort will be the identification of underlying data sets necessary for more dynamic forecasting and planning. We recognize the complexity of this task and parties will need to remain realistic about the time and resources needed to gather information not currently in-hand while determining the full value of such an exercise.

We also propose to explore how we might collectively enhance grid visibility and improve forecasting. As part of this effort, we propose to work collaboratively to develop a strategy for improving probabilistic spatio-temporal forecasting for load, distributed energy resources, and hosting capacity, which could be used to integrate and optimize system updates while minimizing costs.

Our proposal for integrated grid planning advances all three guiding decarbonization principles. Both pieces of this recommendation innovate and supplement industry standard practice, which advances the guiding decarbonization principle to *exemplify climate leadership.* Optimizing how the electric grid is run will also reduce risk of curtailment and downsizing of renewable energy projects, which will support the guiding decarbonization principle to *create incremental power sector decarbonization,* as well as support increased grid utilization for additional beneficial electrification, which advances the guiding decarbonization principle to *facilitate broader decarbonization.* Our proposal also advances guiding principles to *pursue cost-effective solutions, create economic development opportunities,* and ensure solutions are robust and sustainable beyond 2030 by optimizing how we build and use the electric grid with an eye toward long-term goals.

Power Sector Transformation

Key Concept: Continue to advance recommendations described in the Power Sector Transformation stakeholder report

In 2016, Governor Raimondo directed the Division of Public Utilities and Carriers, Office of Energy Resources and Public Utilities Commission to collaborate in developing a more dynamic regulatory framework that will enable Rhode Island and its major investor-owned utility to advance a cleaner, more affordable, and reliable energy system for the twenty-first century.[16] This initiative, called Power Sector Transformation, has three explicit goals: to control the long-term costs of the electric system, to give customers more energy choices and information, and to build a flexible grid to integrate more clean energy generation.

With the support of a robust stakeholder engagement process, the three state agencies produced a report describing a series of recommendations to advance Power Sector Transformation, all of which continue to be relevant today.[17] The report and stakeholder collaboration resulted in National Grid's energy storage and electric transformation initiatives, and is anticipated to result in a refined proposal for grid modernization and advanced metering. Strategic investments to modernize the grid can improve visibility into load and distributed generation, and can improve control to ensure grid reliability. These investments can reduce the cost of maintaining the electric grid and can allow more distributed energy resources to connect to the grid with less-expensive system upgrades.

We propose to continue working to advance the Power Sector Transformation recommendations. Particularly, progress should be made on the following recommendations:

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[16] http://www.ripuc.ri.gov/utilityinfo/electric/GridMod_ltr.pdf

[17] http://www.ripuc.ri.gov/utilityinfo/electric/PST%20Report_Nov_8.pdf

- Improve forecasting and implement a stakeholder engagement plan during forecast development;
- Consider strategies to compensate the value of distributed energy resources based, in part, on their location, and how those incentives align with more proactive distribution system planning;
- Advance electrification that is beneficial to system efficiency and greenhouse gas emission reductions; and
- Consider opportunities for developing performance incentive mechanisms.

Advancement of Power Sector Transformation investments should consider (and appropriately value) the systems and tools required to support more robust deployment of demand response measures and electrification, which can be leveraged to support additional distributed generation and load-shifting. This is in line with the guiding decarbonization principle to *facilitate broader decarbonization*. We also recognize alignment between insights from the Power Sector Transformation initiative and integrated grid planning concepts. These complementary recommendations will advance the guiding decarbonization principle to *create incremental power sector decarbonization* as well as the guiding policy implementation principles to *ensure solutions are robust and sustainable beyond 2030 and be consistent with other Rhode Island priorities and policies.*

Energy Storage and Demand Management

Key Concept: Build out a strategic role for energy storage and demand management technologies

Renewable energy generation profiles do not align with the timing of electricity demand within the day and throughout the year. Rhode Island can rely on the regional system for balancing energy supply with demand in the short term, but as the rest of New England decarbonizes, we will need to participate in developing solutions for balancing supply and demand, both in the very short term and over longer time frames. Energy storage technologies will become increasingly critical to balance the timing of intermittent, non-dispatchable, renewable energy generation with electricity demand and build grid flexibility.[18] Demand management capabilities can address the same problem from the other side, by shifting electricity demand toward times when supply is more available. Doing both of these will improve reliability, reduce the need for fuel-burning backup generation, and reduce risk of curtailment of renewable energy generation, in line with the guiding decarbonization principle to *create incremental power sector decarbonization.*

While short-term energy storage technologies are becoming increasingly prevalent in the market, long-term seasonal energy storage is likely to present the most significant challenges to balancing a heavily weighted renewable energy generation portfolio. Starting now to consider long-term energy storage will advance the guiding decarbonization principle to *facilitate broader decarbonization* as we see increasing electricity demand necessitate increasing penetration of renewable energy resources. Furthermore, long-term strategic thinking will advance the guiding policy implementation principle to *ensure solutions are robust and sustainable beyond 2030.*

Energy storage technology and demand management also provide important resilience and economic development co-benefits. Locally deployed energy storage, such as battery backup systems in Rhode Island homes and businesses, can support shelter-in-place during extreme weather events and reduce costly business interruptions during outages. Deployment of in-state energy storage resources also supports local economic development and employment. Demand management approaches can provide similar benefits. In tandem, these considerations advance the guiding economic principle to *create economic development*

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[18] Energy storage technologies include mechanical storage (e.g. flywheels, pumped hydropower), thermal storage (e.g. water heaters, ice storage), and electrochemical storage (e.g. batteries). For more information, visit http://www.energy.ri.gov/renewable-energy/energy-storage/.

opportunities and the guiding policy implementation principle to be consistent with other Rhode Island priorities and policies.

Over the next several years, we propose to develop a Rhode Island-centric strategic plan for the role of energy storage and demand management as renewable deployment increases through 2030 and beyond. To determine the strategic role of energy storage and demand management, we will need to understand the timing of electricity demand and its potential flexibility, in order to estimate optimal, cost-effective penetration of local energy storage resources. Then we can assess market conditions, gaps and barriers that may prevent Rhode Island from reaching the optimal penetration of these approaches. One such barrier may be interconnection, so we propose to evaluate and potentially pursue updates to interconnection protocols for paired storage-plus-renewable systems and stand-alone energy storage systems.

We also recognize that programs and incentives may help overcome barriers to market growth. We propose to explore the role of programs and incentives in achieving optimal, cost-effective energy storage penetration at beneficial locations on the grid, as well as how demand management capabilities can be acquired and sited. Considering multiple value streams associated with these technologies to of energy storage technology advances the guiding economic principle to pursue cost-effective solutions. We aim to build on existing programs and lessons learned throughout the nation as energy storage technology and demand management are increasingly deployed and the market matures. Lastly, we will engage with municipal stakeholders to accommodate energy storage in local zoning ordinances.

Regional Collaboration

Key Concept: Continue regional collaboration on markets and transmission

Rhode Island's electric grid is part of a highly integrated regional electric system managed by ISO-NE. The other New England states – Connecticut, Massachusetts, Vermont, New Hampshire, and Maine – are all electrically connected and participate in regional wholesale markets for energy and other energy-related attributes as well as in transmission system planning.

Our analysis demonstrates the impact that regional dynamics can have on in-state outcomes. As the grid decarbonizes and electrification proceeds, the need for system upgrades and updated market designs will accelerate.

In 2020, Governor Raimondo was one of five New England governors who called for New England's regional wholesale electricity markets and organizational structures to evolve for a twenty-first century clean energy future.[19] In response, a series of regional technical sessions on these issues is now being developed for early 2021 and will be accessible to stakeholders and the public.

We propose to continue coordination with other New England states on wholesale market designs and transmission planning processes that facilitate energy decarbonization and renewable resource integration across the region. We will coordinate with other New England states on transmission planning processes to better facilitate energy system transformation and proactively plan for the integration of large-scale resources and distributed energy resources across the region, along with identifying and implementing wholesale market mechanisms that fully account for the value of existing and future state-level investments in renewable resources (e.g., avoid rules that require double-procurement of capacity) and meet states' decarbonization mandates and maintain resource adequacy at the lowest possible cost.

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[19] The Governors' Statement is available at: http://nescoe.com/resource-center/govstmt-reforms-oct2020/. The Detailed Vision Statement is available at: http://nescoe.com/resource-center/vision-stmt-oct2020/.

Following through on this recommendation will advance the guiding decarbonization principles to *create incremental power sector decarbonization* and *facilitate broader decarbonization*. Furthermore, this sort of regional collaboration extends beyond Rhode Island to *exemplify climate leadership* at a regional scale.

This recommendation is also in alignment with several additional guiding principles: *pursue cost-effective solutions, improve energy and environmental equity, ensure solutions are robust and sustainable beyond 2030, and be consistent with other RI priorities and policies.*

IV.C Equity Recommendations

The equity recommendations below describe ways to foster equitable outcomes from the clean energy transition and were informed by dialogue with community stakeholders. It is worth reiterating that these equity recommendations do not stand apart from the rest of the recommendations. They are meant to center equity in the previous recommendations, give additional attention to them, and allow these recommendations to be as explicit as possible.

Unlike the policy and planning and enabling recommendations that may all be considered distinct actions that can be pursued in parallel, we propose equity recommendations that have directionality. First, we propose to partner with communities, with a particular emphasis on partnering with frontline communities, environmental justice communities, and communities of color. Then, in collaboration with these communities, we will develop metrics to track progress toward desired equitable outcomes, and adjust programs and policies strategically to improve outcomes that are identified and prioritized by the communities themselves. Community engagement, involvement, and collaboration can lead to innovative, equitable, and inclusive partnerships by connecting the concerns of communities to the decisions that allocate public funds.

We recognize there is a long history of systemic racism and inequities in the United States and Rhode Island that have shaped current systems and processes. Because of those historic legacies, communities of color and environmental justice communities have gained lived experiences crucial to shaping better programs that serve their immediate needs. Throughout this process, we will attempt to identify those inequities within State government and the clean energy sphere and address them whenever possible. Specifically, by recognizing that energy inequities are not solely caused by wealth disparities, we are hoping to shift the narrative from solely focusing on income, which does not provide a full accounting of those in need, and focus on demographics, income, renter status, and other metrics that provide more of an intersectional approach to the problem.[20]

We recognize that we are recommending a process, rather than a solution, and this is deliberate. It is paramount that we listen to and collaborate with communities most impacted by these decisions for direction on how to best serve their needs. As part of this process, we have built in flexibility in our recommendations and timelines for discussion and growth that will hopefully be informed through continued public partnerships. This suite of recommendations advances the guiding principle to *improve energy and environmental equity.*

Community Partnerships

Key Concepts: Partner with and listen to frontline communities about their needs and goals in the clean energy transition

We propose to establish and strengthen partnerships with frontline communities and community organizations with the objective of centering their needs. Frontline communities are

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[20] As used here, intersectionality refers to the theory that various forms of discrimination centered on race, gender, class, disability, sexuality, and other forms of identity, do not work independently but interact to produce particularized forms of social oppression.

Equity Recommendations

We must center equity and include community engagement in program design to improve access to clean energy benefits for all Rhode Islanders. Throughout this effort, we will identify and address systemic racism and historic inequalities.

Partner with trusted community organizations to listen, learn, support, and establish foundational definitions.

Based on foundational definitions, develop **equity metrics** with the community to track and monitor progress towards equitable outcomes.

Improve **outcomes** identified and prioritized by communities through rate design, program adjustments, and policy.

communities who have historically borne a disproportionate burden, endured disproportionate harms, or have missed out on a proportionate share of benefits. Importantly, these communities, often communities of color, have not traditionally been included in decision making or designing of programs and policies. This recommendation seeks to remedy past systemic inequities by listening to these communities, providing support, and collaborating with them throughout the policy development process. Doing so can help strengthen relationships with communities and build trust. It can also lead to a more nuanced understanding of the problems we are trying to solve.

We will leverage existing forums, such as the Executive Climate Change Coordinating Council[21] (EC4) and energy efficiency programs,[22] as appropriate to identify partners, facilitate conversations, and derive guidance for future directions related to equity metrics, desired outcomes, and action items. Resulting feedback should be used to ensure the needs, experiences and priorities of frontline communities are reflected in program design and processes. Specific commitments include:

- Provide access to expert consultation as needed for communities to meaningfully engage in energy discussions and decision making
- Hold listening sessions to increase accessibility to and understanding of energy system basics, and to hold space for community concerns and suggestions
- Integrate equity considerations into energy efficiency plans and program development
- Meet with the community to define equity, benefits, outcomes, and metrics
- Develop rules for equitable engagement and a framework for more inclusive and accessible public meetings across the energy and environmental space.

Furthermore, we propose to target community-based training efforts to support in-demand clean energy jobs. To support workforce development in-state, we will explore other state models and programs focused on underserved communities in order to leverage best practices and lessons learned. This

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[21] The Executive Climate Change Coordinating Council (EC4) is a public facing entity comprised of officials from state agencies with responsibility and oversight relating to assessing, integrating, and coordinating climate change efforts, as set forth in the Resilient Rhode Island Act (RIGL 42-6.2).

[22] Specifically, National Grid has proposed to convene an Energy Equity Working Group in 2021 to inform energy efficiency program development and evaluation (Section 8.1.2 of the proposed 2021-2023 Three-Year Energy Efficiency Program Plan: http://www.ripuc.ri.gov/eventsactions/docket/5076-NGrid-2021EEPlan(10-15-2020).pdf).

recommendation advances the guiding economic principle to *create economic development opportunities*.

We recognize the importance of education in meaningful participation, so we propose to provide education about the opportunities and challenges available in creating clean energy programs and policies, and information about energy programs, including comparative costs and benefits. Internally, OER and other state agencies should continue to improve on their understanding of systemic racism, social justice, and energy and environmental equity.

Equity Metrics

Key Concept: Develop metrics to track progress toward community-identified equity outcomes

Following discussion with and guidance from frontline communities and community organizations, we propose to identify and track metrics that indicate progress toward community-identified equity outcomes. Community engagement will drive development of qualitative and quantitative equity measures that can also inform program design. Critical to this effort is direction from communities regarding their visions for participation in the clean energy transition.

Some metrics related to equity are already tracked and those existing processes may be leveraged if deemed useful. These include workforce diversity (tracked via the annual Clean Energy Jobs Report[23]), participation of people with low- and moderate-income in clean energy programs, renter status and non-participation in energy efficiency programs, and metrics related to use of the low-income rate and other utility bill support programs. Additional metrics may include but are not limited to energy burden, demographic information, participation in public workshops and decision-making processes, and others.

While we present currently tracked metrics and potential new metrics, we ultimately turn to community partners for additional guidance on how to identify and track metrics focused on addressing systemic racism and historic inequities. These metrics may fall outside of what may be seen as normal energy metrics, such as housing indicators, health data, and technological access; however, in an effort to incorporate an intersectional approach, following community guidance and best practices from other states will be critical.

Improve Community-Determined Outcomes

Key Concept: Improve outcomes identified and prioritized by communities through rate design, program adjustments, and policy

Given guidance from frontline communities and community organizations, we will partner with communities to develop and implement plans to improve priority outcomes.

For example, if, through collaboration, education, and consultation, community partners prioritize improved access as a desired means to provide equity, then we will focus on actions that will make participation easier, reduce financial burdens, and protect consumers. First, program participation should be made as easy as possible. Barriers to participation should be reduced through effective and culturally competent program design and delivery. This includes materials that are available in multiple languages that represent areas being served, and streamlined eligibility verification processes to reduce customer burden for proving income or need.

Second, programs should aim to reduce financial burdens, and should provide support for low- and moderate-income households and frontline communities beyond installing technology, including structures for aiding with upkeep and services.

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[23] http://www.energy.ri.gov/cleanjobs/

Third, programs should carefully consider consumer protection for all customers and determine whether additional protections for underserved customers may be needed. For example, programs that deliver energy efficiency services should also conduct heating system safety checks.

If instead, for example, through collaboration, education, and consultation, community partners prioritize improved programmatic benefits as a desired means to provide equity, then we will focus on prioritizing energy efficiency, ensuring equitable distribution of benefits and costs, and looking beyond carveouts to ensure equitable impacts.

First, programs and planning should ensure that low- and moderate-income households and frontline communities can access energy efficiency benefits as an important step for reducing energy burdens, alleviating energy poverty, and increasing household comfort and health.

Second, in tandem with tracking equity metrics, those metrics should be used to monitor and verify equitable distribution of costs and benefits. In addition to utility bill savings, benefits such as pollution reduction and increase in home comfort and health should be equitably distributed. This will ensure we are serving all populations, not just those based on economic status. We turn to communities for guidance on which benefits are most important to improve and therefore most critical to track. We recognize that achieving 100% renewables will increase costs to drive long-term energy, economic, and environmental benefits – this requires careful consideration among communities and within program and policy development.

Lastly, we recommend looking beyond carveouts as programmatic mechanisms to ensure participation by underserved communities. Programs should do more than set aside a small portion of benefits for frontline communities. Carveouts can be the first step, but they cannot be the final step, to ensuring more deserving communities can benefit from programs. Whenever possible, programs and processes should use a targeted approach with a universal goal to achieve equitable outcomes.

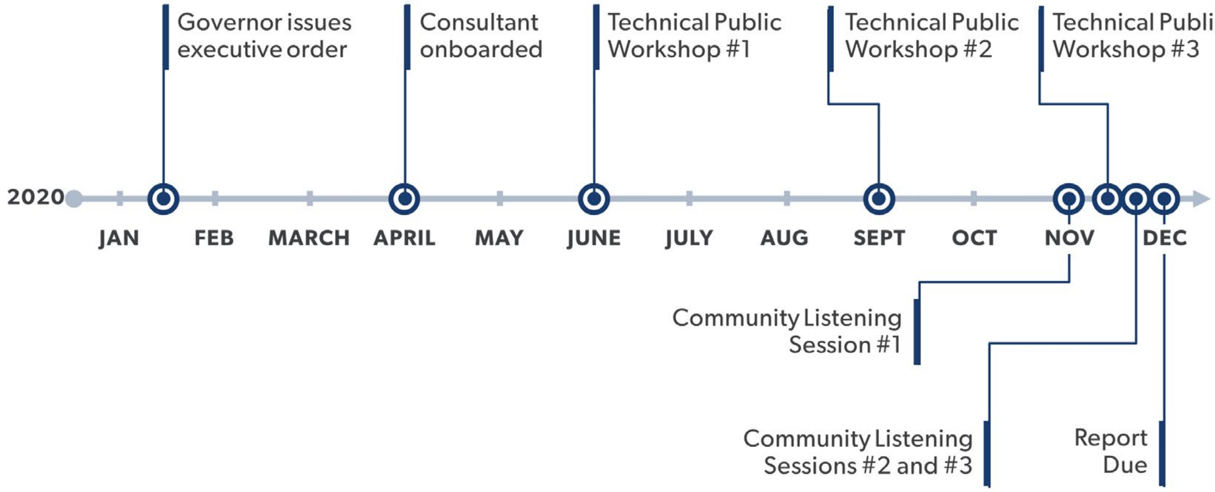
Importantly, based on community input, these recommendations may change or may be combined to prioritize both improved access and improved programmatic benefits. We must ultimately strive to prioritize the concerns of the community and address systemic inequities from our position of power as best we can.

Appendix: Summary of Stakeholder Engagement

Stakeholder engagement was a key component of this study, designed to learn from, engage and inform stakeholders. This Appendix contains an overview of the public comment process and summaries of the comments and questions received, along with the project team's responses. Following that is a list of the organizations that provided comments, and demographic information that was shared by the attendees at the public technical workshops and the community listening sessions.

A.I Summary of Public Comment Process

To obtain feedback from a broad range of stakeholders and experts, the Office of Energy Resources held three public community listening sessions, three public technical workshops, and accepted written public comments from the start of the project through December 15, 2020. The technical workshops were held in June, September, and December with a primary focus on analytical methods, results, and policy implications. The community listening sessions were held in November and December and less technical in nature, with a focus on policy and programmatic recommendations. Meeting materials are available on www.



energy.ri.gov/100percent/. Due to the COVID-19 pandemic, all workshops and listening sessions were conducted virtually. This Appendix summarizes feedback and written comments from these sessions, which helped to inform our final report.

In total, 13 written comments were received via email from stakeholders and organizations, and over 245 comments and questions were raised verbally or via virtual chat during the listening sessions and technical workshops. A list of over thirty-five organizations that provided input is provided near the end of this summary. In addition, aggregated demographic information provided by public participants is provided at the end of this section. Overall, summary statistics provide directional insights that suggest underrepresentation from several demographic groups.

This appendix does not include every comment received; however, it aims to thoroughly summarize comments and responses related to all three policy and programmatic recommendation categories: policy, planning & enabling, and equity. This appendix is organized into sections based on recommendations versus comments and concerns raised.

Stakeholder Comments Related to Policy Recommendations

Legislation

Comment: Stakeholders recommended working with the General Assembly to pass a 100% by 2030 Renewable Energy Standard (RES).

Response: *This recommendation is consistent with our policy recommendation to advance a 100% Renewable Energy Standard.*

Comment: Stakeholders asked clarifying questions about Renewable Energy Certificates (RECs) and their associated market. Some stakeholders suggested that meeting the 100% renewable electricity goal with RECs from across New England was appropriate. However, other stakeholders suggested a preference for in-state development and associated economic development over the purchase of regional RECs. The issue of double counting RECs was also raised by a few stakeholders.

Response: *This recommendation is consistent with our proposal to define achieving 100% renewable electricity with an amended Renewable Energy Standard. The utilization of RECs establishes a verifiable mechanism to ensure compliance while facilitating renewable energy project financing. OER also acknowledges that counting RECs from local Distributed Generation is critical to tracking progress towards the 100% renewable electricity goal. Reporting on this is conducted annually by the Public Utilities Commission. We recognize there are tradeoffs between the comparative affordability of meeting the goal through procuring regional RECs versus delivering in-state benefits through local development, and will strive to maximize value to Rhode Islanders through policies and programs.*

Comment: Stakeholders recommended a form of carbon pricing mechanism to be proposed in legislation.

Response: *Carbon pricing may be a viable supplementary policy to promote economy-wide decarbonization but is outside the scope of this specific project.*

Comment: Avoiding greenhouse gas emissions and reducing the use of fossil fuels were major concerns for community members. Shutting down fossil fuel power plants was one desired outcome voiced by multiple stakeholders. These plants were described as contributing to local pollution and are often located near frontline communities.

Response: *Please refer to the sidebar, "Does '100% Renewable' require shutting down all fossil generation in Rhode Island?" on page 10.*

Comment: Stakeholders voiced concerns over total ratepayer costs of achieving 100% renewable electricity.

Response: *Utility bills will increase regardless of our ultimate portfolio of renewable resources – but net economic and energy* *benefits and costs will be determined by how that portfolio is shaped over time. Achievement of our clean energy future will require ratepayers to support investment to drive long-term energy, economic, and environmental benefits through charges on their bills. However, we must keep in mind that we are already facing increasing costs of a changing climate outside of utility bills, and the investments we make in a clean energy future will yield incremental energy, economic, and environmental benefits for Rhode Islanders, as demonstrated in our report.*

Renewable Energy Programs

Comment: Stakeholders recommended the Renewable Energy Growth (REG) feed-in-tariff program be extended and expanded to provide in-state renewable energy development, allowing for pricing mechanisms to align energy development with policy goals.

Response: *This recommendation informed our policy recommendation to continue to support utility-scale renewable procurements and local renewable development that reflects evolving market conditions.*

Comment: Stakeholders recommended ensuring renewable energy programs were compatible with energy storage.

Response: *This recommendation is in line with the guiding policy implementation principle to build upon Rhode Island's existing renewable energy programs and informs the planning and enabling recommendation to develop a strategic role for energy storage.*

Comment: Stakeholders voiced concerns about the Renewable Energy Fund (REF) incentive program, including scale and allocation of available funding. Stakeholders recommended REF be extended beyond its current 2022 sunset date and should evolve to address changing market conditions.

Response: *This recommendation informed our policy recommendation to continue to support utility-scale renewable procurements and local renewable development that reflects evolving market conditions.*

Comment: Stakeholders recommended that changing market conditions be monitored and studied. Specifically, stakeholders suggested that OER adapt policies and programs to changing circumstances and evaluate market conditions on a rolling basis, similar to other New England states.

Response: *This comment informs our policy recommendation regarding continued support for local renewable energy development and pursuing program evolution that may improve affordability and better respond to evolving market conditions.*

Comment: Stakeholders described concerns over renewable energy project siting – particularly project development in open space and environmentally sensitive lands – and recommended strategic action to alleviate siting concerns and protect greenspace. Stakeholders raised concerns over clear cutting forests to site renewable energy projects. The value of maintaining forests in order to combat climate change was described as an important priority.

Response: *Environmental protection is one example of a policy objective that should be pursued in parallel to decarbonization, consistent with our guiding policy implementation principle to 'be consistent with other Rhode Island priorities and policies'. OER recognizes the authority of municipal governments in developing renewable energy zoning ordinances, and offers technical support as needed. The planning and enabling recommendation related to integrated grid planning attempts to bring key stakeholders together to explore how we may be able to integrate distributed energy resources in a manner that advances multiple policy objectives in parallel.*

Alternative Renewable Energy Resources

Comment: Stakeholders recommended expanding the eligibility of existing small-scale hydropower to hedge against new resource delays and project attrition.

Response: *While hydropower may offer some limited in-state renewable energy generation, it is not recognized as a primary* *growth resource in Rhode Island and is not a significant part of the recommendations from this study. OER agrees that policies should ensure that all renewable technologies can compete to deliver renewable energy at cost-competitive prices to Rhode Island, consistent with the guiding economic principle to pursue cost-effective solutions.*

Comment: Stakeholders recommended exploring nuclear capacity as a potential technology option for achieving 100% renewable electricity by 2030.

Response: *Nuclear energy will continue to be a part of New England's generation portfolio for some time, represented by Connecticut's Millstone Nuclear Plan and New Hampshire's Seabrook facility. However, no new nuclear energy resources are planned for construction in the foreseeable future.*

Comment: Stakeholders suggested that Rhode Island's capacity for land-based wind is a viable option to support the 100% renewable electricity goal.

Response: *Land-based wind is indeed a viable option to support the 100% renewable electricity by 2030 goal. The analysis considers land-based wind as a Technology Bookend as well as a (small) component of mixed portfolio #10 commensurate with likely future opportunities for siting and development. A regional transmission solution might enable the development of materially more land-based wind than has been considered here, though that might not be in place in time for this technology to play a significant role in Rhode Island's 2030 goal.*

Comment: Stakeholders recommended that geothermal energy be considered as a viable renewable energy technology.

Response: *Even though geothermal energy is a potential source for power generation, it was not included in this study as the geothermal resources in New England do not produce electricity. Geothermal electricity production is only emerging in parts of the world where the earth is hot near the surface and is not a viable option in Rhode Island. Even if this resource were to progress, the technologies would most likely not be available before 2030. Instead this study classified geothermal as a viable technology to reduce electricity demand.*

Stakeholder Comments Related to Planning and Enabling Recommendations Grid Modernization, Energy Storage, & Transparency

Comment: Various stakeholders were concerned that the topics of energy storage and grid modernization were not explicitly included in the analysis. It was also suggested that pre-discounted nameplate capacity values should also be considered when displaying solar PV forecasts to ensure that the scale of necessary development is clear.

Response: *The analysis does not factor grid modernization, energy storage, or other advancements that may facilitate integration of distributed energy resources at this time. However, planning and enabling recommendations include support for such advancements, including exploring an integrated grid planning approach, continuing to drive recommendations related to Power Sector Transformation, and developing a strategic role for energy storage. Solar PV capacity needs shown in the analysis represent nameplate capacity. Further details about capacity factors and other assumptions used in the analysis can be found in the Technical Support Document.*

Stakeholder Comments Related to Equity

Comment: Stakeholders recommended that environmental justice and equity should be prioritized in the state's clean energy transition. Furthermore, stakeholders recommended that OER prioritize income-eligible residents and underserved communities.

Response: *This recommendation informed our suite of equity recommendations to partner with frontline communities, develop and track equity metrics, and make adjustments to drive community-prioritized equity outcomes. Centering equity and including community engagement in program design is a main focus for OER, as it is one of our core principles.*

Comment: Stakeholders supported the concept of an incentive adder for low- and moderate-income customers but raised concerns about the adder being overly restrictive. Stakeholders suggested prioritizing solar projects that benefit low- and moderate-income individuals.

Response: *OER acknowledges that programs need to support more equitable outcomes and is committed to centering equity and including community engagement in program design to improve access to clean energy benefits for all Rhode Islanders. This recommendation informed the suite of equity recommendations whereby we will strengthen partnerships with frontline communities to identify ways in which we can drive community-prioritized outcomes.*

Comment: Stakeholders voiced the importance of community engagement and recommended increasing public understanding of the benefits of renewable energy.

Response: *Stakeholder and community engagement are critical for success, and recommendations like this informed the suite of equity recommendations. Specifically, we recommend partnering with frontline communities and community organizations and supporting communities such as by developing frameworks for more inclusive and accessible public meetings across the energy and environmental space. OER is committed to including community members and stakeholders in development, implementation, and decision-making for all project recommendations.*

Stakeholder Comments Related to the Analysis

Comment: Stakeholders recommended additional detailed analysis for different categories of solar projects. Stakeholders posit that high costs are due to large-scale solar, so focus should be shifted to rooftop projects that have lower interconnection costs along with a higher probability of completion with a shorter timeframe.

Response: *The analysis differentiates between wholesale (utility-scale) and retail (small-scale) solar projects. Ranges in resource acquisition costs are reflected in the cost ranges provided for each portfolio. OER acknowledges that interconnection costs of distributed solar resources have risen over time and are likely to continue to do so without a more advanced, dynamic planning approach. Stakeholder concerns over interconnection costs and delays informed the planning and enabling recommendation related to integrated grid planning.*

Comment: Stakeholders recommended the high-demand forecast be used for planning purposes.

Response: *The Base load forecast was used for the analyses. Sensitivity analysis showed that load forecast uncertainty at the level assessed is a relatively modest contributor to overall cost uncertainty (higher load would result in higher overall costs, though not necessarily in higher unit rates.) The load forecast can be updated over time as 2030 approaches to adjust the amount of renewable energy that is targeted. In any case, even if the forecast is quite accurate, there will be some residual mismatch between the 2030 energy production of the renewable resources acquired and actual 2030 load, both of which are variable in response to weather and other factors. The structure of a 100% RES requirement enables matching renewable production to actual load by buying or selling RECs to resolve any residual mismatch. This is discussed in* **SECTION II.C** *above.*

A.II Public Commenters (listed alphabetically)

Acadia Center

Anbaric Development Partners

Audubon Society of Rhode Island

Brookfield Renewable

Brown University

Coalition Center for Environmental Sustainability (CC4ES)

Department of Environmental Management

E2SOL LLC

EarlyBird Power

Ecogy

ecoRI

Great River Hydro, LLC

Green Development, LLC

Green Energy Consumers Alliance

Grow Smart RI

Handy Law LLC

Hexagon Energy

HousingWorks RI

Kearsarge Energy

Longwood Energy Group

National Biodiesel Board

National Grid

National Wildlife Foundation

NEC Solar

New England Power Generations Association

Newport Solar

Northeast Clean Energy Council

Northeast Energy Efficiency Partnerships

Ocean Wave Energy Company (OWECO)

Preservation of Affordable Housing

Rhode Island Center for Justice

Rhode Island Chapter of Citizens Climate Lobby

Rhode Island Public Utilities Commission

SEA RI

Sunrise Climate Movement

Sunrun

The Nature Conservancy

Trinity Solar

University of Rhode Island

West Broadway Neighborhood Association

Approximately 80 individuals not representing specific organizations provided oral and written comments

A.III Demographic Information from Workshops & Listening Sessions

Over the course of the year, OER held three public technical workshops that focused on the project's technical analysis and three listening sessions focused on answering questions and hearing community concerns.In aggregate, 543 people attended these workshops and listening sessions, though many people attended multiple events. We received 208 survey responses, resulting in a 40.8 percent response rate.[1] We summarize participation along demographic dimensions based on survey responses and compare participation to statewide demographic data. While we are unable to glean statistical accuracy or tease out self-selection bias from survey findings, these summary statistics provide directional insights that suggest underrepresentation from several demographic groups.

Race: Of the 208 survey respondents, 144 answered questions relating to their race. Of those respondents, the majority, 81.25 percent, identified as White or Caucasian. The state of Rhode Island is estimated to be 83.6 percent white according to U.S. Census data from 2018.[2] The Black population in the state is estimated to be 8.5 percent. The survey participants who identified as "Black or African-American" equaled 3.5 percent of the survey responses. Aside from White people, all other races were likely underrepresented.[3]

Race/Ethnicity	Survey Respondents (%)	Rhode Island population estimate (%)
White/ Caucasian	81.3%	83.6%
Black/ African-American	3.5%	8.5%
Asian/ Asian-American	2.1%	3.7%
American Indian or Alaskan Native	0.7%	1.1%
Native Hawaiian or Pacific Islander	0.0%	0.2%
Hispanic or Latino, any race	3.5%	16.3%
Prefer not to Say	9.7%	

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[1] N=543 and N=208 do not represent unique attendee or respondent counts, but rather indicate aggregate sums of attendees and respondents.

[2] https://www.census.gov/quickfacts/fact/table/RI/PST045219#

[3] https://www.census.gov/quickfacts/fact/table/RI/PST045219#

Age: Of the 208 survey respondents, 145 answered questions relating to their age. Ages 25-64 were slightly over-represented in these public meetings, and ages Under 18 and 65+ were underrepresented.[4]

Age	Survey Respondents (%)	Rhode Island population estimate (%)
Under 18	2.1%	19.3%
18-24	6.2%	10.7%
25-34	17.2%	13.8%
35-44	16.6%	11.7%
45-54	17.9%	13.2%
55-64	15.9%	14.1%
65+	10.3%	17.3%
Prefer not to Say	4.8%	

Income: The income information gathered from the survey demonstrates a higher attendance from people earning $100,000 or more annually, and a lower representation from people who may identify as low- and moderate-income households. Survey results, when compared with state demographic data, show that families earning $15,000 or less annually were underrepresented at 4.9 percent of attendees (compared to 12 percent of the state). It should be noted that 24.4% of survey respondents preferred not to disclose their family income.

Income	Survey Respondents (%)	Rhode Island population estimate (%)
Under $15,000	4.9%	12.0%
Between $15,000 and $29,999	2.4%	7.8%
Between $30,000 and $49,999	7.3%	14.9%
Between $50,000 and $74,999	13.0%	17.4%
Between $75,000 and $99,999	12.2%	12.1%
Between $100,000 and $150,000	20.3%	17.1%
Over $150,000	15.4%	14.3%
Prefer not to say	24.4%	

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[4] https://censusreporter.org/data/table/?table=B01001&geo_ids=04000US44,01000US&primary_geo_id=04000US44, data in graph is gender-blind.

Gender: According to the 5-year ACS data in 2018, approximately 51.2 percent of the state population is female and 48.8 percent of the state population is male. Survey results indicate that 39 percent of respondents identified as women, demonstrating an underrepresentation from women. 6.2 percent of respondents chose not to self-report their gender information, and no respondents identified as non-binary or trans.

Gender	Survey Respondents (%)	Rhode Island population estimate (%)
Woman	39.0%	51.2%
Man	54.8%	48.8%
Prefer not to say	6.2%	

Sector: Responses suggest that the 100% Renewable Electricity workshops and listening sessions were heavily attended by folks within the energy industry, comprising 37.8 percent of poll responses. The events were least attended by municipal governments and by residential or business customers, comprising 2.8 percent and 9.8 percent of poll responses, respectively.

Sector	Survey Respondents (%)
Environmental Organization	14.0%
Industry, including vendors, developers, and energy consultants	37.8%
Municipal Government	2.8%
Other	18.9%
Residential or Business Customer	9.8%
State Government	16.8%

Familiarity: Most survey respondents, 65.3 percent, stated familiarity with the energy and electricity system. 18.4% of participants self-identified as experts, and 9.5% of participants were not at all familiar with the energy and electricity system.

Familiarity	Survey Respondents (%)
Expert	18.4%
Familiar	65.3%
Not at all Familiar	9.5%

Glossary

Decarbonize	Reduce carbon emissions (greenhouse gases, or GHGs) by substituting non-fossil energy sources for electricity or in other sectors
Energy	Electric energy that is actually produced and delivered to end users
Capacity	The ability to produce energy on demand, traditionally required to meet peak loads
Heat Pump	Reversible electric heating/cooling equipment that uses technology similar to an air conditioner; can heat in winter as well as cool in summer
Renewable Energy Standard (RES)	RI 2004 legislation requires that renewable energy meet a minimum percentage of electric load, currently 16%, growing 1.5%/year; other NE states have similar RES
Renewable Energy Credit (REC)	Represents the renewable attribute of 1 MWh of renewable generation; RECs are tradeable, and used to meet the RES requirement
Renewable Energy Growth Program	Program to solicit and support smaller scale renewable projects in RI, primarily solar and wind
Renewable Energy Fund	Program of grants and loans for renewable energy technologies in RI; also direct funding for residential and commercial installations
Competitive Procurement	Competitive process used to acquire long-term contracts for renewable energy (e.g., the 400 MW Revolution Wind offshore wind project)

Division 3-23

Questions on Bonenberger Testimony

Request:

[Bonenberger testimony] Please provide on an annual basis for all years available, the number of site visits for meter disconnects and reconnects and the reason that required a site visit if other than disconnect/reconnect.

Response:

Pursuant to the Transition Services Agreement, National Grid USA ("National Grid") provided Rhode Island Energy with the number of site visits for the previous thirteen years based on the available data in National Grid's systems as per the charts below. More detailed definitions of category types are provided below the charts. Resource Coordination functions, which were used to summarize this data into categories, did not exist prior to 2018; therefore, it was necessary to map old systems to these standard codes. Counts during 2021 and 2022 were reduced due to the Covid pandemic because the Company was unable to perform Turn-Off – Non-Payment work and there were fewer field calls in general during that period.

	JOBS QUANTITY					
DESCRIPTION	FY10	FY11	FY12	FY13	FY14	FY15
EMERGENCY INVESTIGATIONS - NO ELECTRIC SERVICE, ABNORMAL VOLTAGE	2,272	1,560	1,070	967	905	1,118
TURN OFF - METER (METER - OFF/LOCKED)	10,350	9,744	8,694	8,080	8,679	7,141
TURN ON - METER	41,472	41,632	34,301	26,212	27,268	32,213
INSTALL/REMOVE - RECORDING VOLT METER	22	35	34	47	51	40
INSTALL/REMOVE - SEALS AND LOCKS	1,689	1,765	1,582	1,165	1,349	1,259
INVESTIGATE METER	12,566	14,036	17,641	14,212	12,099	9,237
READ - METER	6,809	6,013	4,552	4,644	4,118	4,979
TURN OFF - NON-PAYMENT	49,362	40,462	31,428	20,576	19,766	28,537
CHANGE METER - MANDATED, SERVICE, OTHER	9,324	11,166	9,948	9,036	10,280	9,771
INSTALL/REMOVE - METER	3,025	2,882	3,136	3,833	3,186	3,399

	JOBS QUANTITY						
DESCRIPTION	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
EMERGENCY INVESTIGATIONS - NO ELECTRIC SERVICE, ABNORMAL VOLTAGE	1,255	1,172	1,446	1,792	1,155	237	576
TURN OFF - METER (METER - OFF/LOCKED)	7,388	6,038	5,928	6,319	5,163	968	1,336
TURN ON - METER	32,556	33,074	28,556	26,158	23,162	4,237	10,829
INSTALL/REMOVE - RECORDING VOLT METER	13	24	23	24	10	9	7
INSTALL/REMOVE - SEALS AND LOCKS	1,221	1,264	1,003	1,345	942	871	776
INVESTIGATE METER	7,870	9,675	6,058	7,745	3,436	2,515	3,268
READ - METER	4,220	4,308	5,206	3,468	2,362	932	1,770
TURN OFF - NON-PAYMENT*	34,901	19,403	42,397	43,462	43,782	91	7,341
CHANGE METER - MANDATED, SERVICE, OTHER	12,585	11,030	11,438	11,652	10,409	7,661	11,628
INSTALL/REMOVE - METER	3,977	3,814	4,168	5,638	3,359	2,971	3,385

EMERGENCY INVESTIGATIONS – Priority orders based on conditions impacting a customer's service. These may also include priority connects or move in orders.

TURN OFF - METER – Orders created to shut off meters for customers who are moving out.

TURN ON - METER – Orders created to establish service for customers who are moving on or to re-establish service for customers who have made payments as a result of a credit related termination of service. The volumes of these orders will decrease significantly with remote switch functionality introduced with AMF.

INSTALL/REMOVE RECORDING VOLT METER – Recording volt meters may be installed at a premise to record voltage at the meter over an extended period of time. The volumes of these orders will decrease with the AMF ability to measure voltage at the meter in 15 minute intervals.

INSTALL/REMOVE SEALS AND LOCKS – Orders created to remove or re-install meter locks and seals for electricians performing work at a customer premise.

INVESTIGATIONS – Orders created to investigate a potential meter issue that fall into the following sub categories:

- Potential Billing issues
- Suspected meter failure
- Energy usage registered on an inactive meter. The volumes of these orders will decrease significantly with remote switch functionality introduced with AMF.

- Verify meter number
- Suspected meter tampering

READ METER – Orders created to obtain a manual meter read for meters that were unable to be read during normal routes. The volumes of these orders will decrease with the AMF ability to obtain on demand reads over the air as well as the accuracy of the RF network to read meters. In Pennsylvania, billing and interval read rate performance is approximately 99.5%.

CHANGE METER – Orders created to exchange a meter. These orders could be a result of a meter investigation or part of the annual regulatory pick for test random sample meter exchanges.

TURN OFF - NON-PAYMENT – Orders created to shut off meters for credit related reasons.

INSTALL/REMOVE METER – Orders created to install or remove a meter at a premise. These orders are primarily associated with installing meters for new customers or removing meters associated with inactive accounts.

Division 3-24

Questions on Bonenberger Testimony

Request:

[Bonenberger testimony] Please provide data in support of the statement that PPL is "...one of first utilities in country to use automatic reclosers system-wide and ADMS software in conjunction with AMF meter information,…ultimately top decile performance".

Response:

Since 2010, PPL Electric Utilities Corporation's ("PPL Electric") strategy has been to invest in remote operation and monitoring to improve reliability and facilitate the move toward condition based maintenance. Around 2011, PPL Electric began distribution automation investments to improve sectionalization, which led to a replacement of its three-phase hydraulic reclosers with communication-enabled vacuum circuit reclosers that started in 2015.

The system-wide automation investment resulted in national recognition that continued over time, highlighting how leadership and innovation were delivering business results. For example, in 2016, T&D World Magazine published an article,[1] "PPL Electric Utilities Introduces Automated Power Restoration System." Systemwide installation of advanced field devices were the foundation for fault isolation and service restoration ("FISR") and other advanced distribution management system ("ADMS") development. Second-generation advanced meter reading infrastructure was installed from 2015 to 2019. By 2019, PPL Electric was being recognized for leadership in the marketplace to innovate. As an example, the Smart Electric Power Alliance ("SEPA") provided PPL Electric with recognition of the "Investor-Owned Utility of the Year."[2] The award recognized PPL Electric for the creation of the next generation of advanced DMS functionalities through its Distributed Energy Resource Management System ("DERMS"). The same year, PPL Electric was awarded the 2019 ReliabilityOne™ Most Improved Utility Award.[3] In 2020, T&D World Magazine published an article, "PPL Smart Grid Tops One Million Avoided Customer Outages Since 2015,"[4] which

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[1] https://www.tdworld.com/smart-utility/article/20966649/ppl-electric-utilities-introduces-automated-power-restoration-system

[2] https://sepapower.org/knowledge/sepas-2019-power-player-award-winners/

[3] https://www.northcentralpa.com/business/ppl-electric-utilities-receives-most-improved-utility-award/article_d35d5dfc-0cd1-11ea-acb7-cb94524d8173.html

[4] https://www.tdworld.com/smart-utility/article/21140940/ppl-smart-grid-tops-one-million-avoided-customer-outages-since-2015

summarized PPL Electric's journey to avoid outages with smart grid investments. One of the more recent recognitions is the 2022 POWER Magazine Smart Grid Award Winner,[5] which states "PPL Electric was the first utility to centrally install FISR across its entire service territory to automate restorations. That network of smart devices, coupled with GE's advanced software system (ADMS), has assisted PPL Electric in creating an autonomous, self-healing grid. In fact, since 2015, PPL Electric's smart grid has helped prevent more than 1.4 million customer outages. And, in 2021 alone, customers experienced 34% fewer outages compared to the average over the prior five years."

This wide array and ongoing national recognition showcase PPL Electric's leadership and industry innovation for smart grid deployment, which includes the integration of system-wide recloser deployment and AMF that is fully integrated with ADMS.

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[5] https://www.prnewswire.com/news-releases/ppl-electric-utilities-earns-2022-power-magazine-smart-grid-award-301611877.html

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Division 3-25

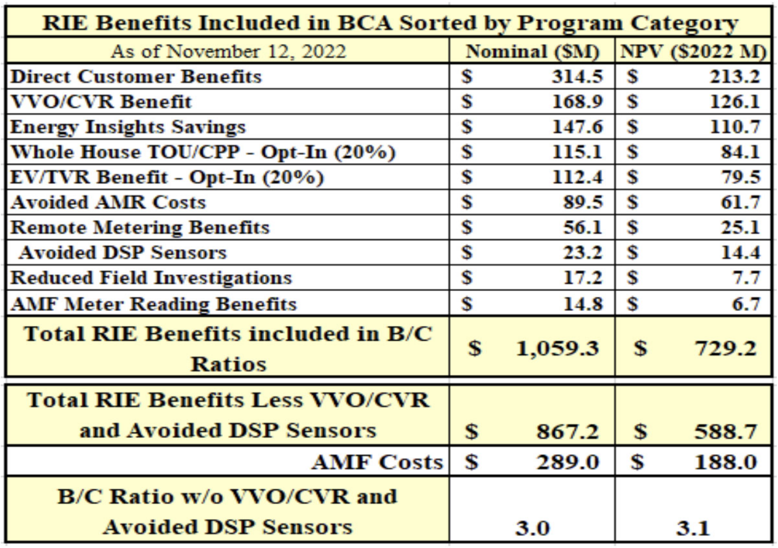
Questions on Bonenberger Testimony

Request:

[Bonenberger testimony] On page 20, the witness states: "When compared to the costs of $188.0 million NPV, the Benefit/Cost ("B/C") ratio is strong at 3.9 NPV. When the benefits from the GMP are decoupled from AMF, the AMF stand-alone B/C ratio remains significantly above 1.0, at 3.1 NPV, making a strong and compelling case to proceed with AMF now." Please provide the benefit categories characterized as "benefits from GMP" along with the present value of these benefits.

Response:

A sensitivity analysis was performed to address benefits in the advanced metering functionality ("AMF") business case that were dependent on the Grid Modernization Plan ("GMP"). The sensitivity that addresses this question was discussed on Bates page 174 of Rhode Island Energy's AMF Business case. Figure 11.36 in the AMF filing, which is reproduced below, shows the results of the analysis. To summarize, there are two benefits that will not be realized if the Commission approves AMF but does not approve GMP. These benefits are VVO/CVR and Avoided DSP Sensors. When these two benefits are removed from the totals, the B/C ratios are 3.0 Nominal and 3.1 NPV ($2022).



RIE Benefits Included in BCA Sorted by Program Category		
As of November 12, 2022	Nominal ($M)	NPV ($2022 M)
Direct Customer Benefits	$ 314.5	$ 213.2
VVO/CVR Benefit	$ 168.9	$ 126.1
Energy Insights Savings	$ 147.6	$ 110.7
Whole House TOU/CPP - Opt-In (20%)	$ 115.1	$ 84.1
EV/TVR Benefit - Opt-In (20%)	$ 112.4	$ 79.5
Avoided AMR Costs	$ 89.5	$ 61.7
Remote Metering Benefits	$ 56.1	$ 25.1
Avoided DSP Sensors	$ 23.2	$ 14.4
Reduced Field Investigations	$ 17.2	$ 7.7
AMF Meter Reading Benefits	$ 14.8	$ 6.7
Total RIE Benefits included in B/C Ratios	**$ 1,059.3**	**$ 729.2**
Total RIE Benefits Less VVO/CVR and Avoided DSP Sensors	**$ 867.2**	**$ 588.7**
AMF Costs	**$ 289.0**	**$ 188.0**
B/C Ratio w/o VVO/CVR and Avoided DSP Sensors	**3.0**	**3.1**

Prepared by or under the supervision of: Wanda Reder

Division 3-26

The data requests numbered DIV 3-26 through DIV 3-30 pertain to AMF BCA Attachment H FINAL (Confidential)

Request:

For Excel file AMF BCA Attachment H FINAL (Confidential), Worksheet 5-Benefit Inputs, Rows 334-373, please provide the exact source and any derivations for the basic data inputs for the following:

- Column E – Wholesale Average $/kWh (Whole)
- Column G – Rhode Island Non-Embed GHG Cost-Ann Avg $/kWh (Whole)
- Column I – Rhode Island Non-Embed NOX Cost-Ann Avg $/kWh (Whole)
- Column K – Rhode Island RPS Compliance $/kWh (Whole)
- Column M – Public Health Avg (Same as National Grid) $/MWh (Ret)
- Column N – Rhode Island Intrastate Energy DRIPE $/kWh (Whole)
- Column P – Cleared $/kW-year (Whole)
- Column R – Uncleared $kW-year
- Columns S-V- Capacity DRIPE (20-yr lifetime)
- Columns AA-AD - Capacity DRIPE (Bid capacity/Cleared) - Calculation for Use in Estimating Benefit #709

Response:

The bulk of the information in these columns, with the exceptions of the Public Health values and Columns AA-AD, was sourced from Synapse Energy Economic's AESC 2021 User Interface, which is part of the AESC 2021 Report. The User Interface is a spreadsheet that allows users to access data specific to their state for use in calculating avoided costs. The spreadsheet can be found at https://www.synapse-energy.com/project/aesc-2021-materials.

Prepared by or under the supervision of: Wanda Reder

The specific information is contained in the "User Interface" files at the above url. When the CF4 User Interface is downloaded, the user must go to the User Interface tab in the file and input the appropriate information. In this case that means the Region is Rhode Island, the lifetime of the measure is 20 years and the cost of carbon is the social cost of carbon.

Once these three inputs are identified the information will be in the cells indicated below in blue.

- Column E – Wholesale Average $/kWh (Whole) – D40-60
- Column G – Rhode Island Non-Embed GHG Cost-Ann Avg $/kWh (Whole) – K40-60
- Column I – Rhode Island Non-Embed NOX Cost-Ann Avg $/kWh (Whole) – Q40-60
- Column K – Rhode Island RPS Compliance $/kWh (Whole) – J40-60
- Column N – Rhode Island Intrastate Energy DRIPE $/kWh (Whole) – W40-48
- Column P – Cleared $/kW-year (Whole) – AM40-60
- Column R – Uncleared $kW-year – AN40-60
- Columns S-V- Capacity DRIPE (20-yr lifetime) – AO40-60; AP40-60; AQ20-40; AR20-40

The information in Columns AA-AD was sourced from Synapse Energy's 2018 AESC Report/User Interface which can be found at the url shown below:
https://synapseenergyeconomics.app.box.com/s/az1nrl5qh7k2feog3wk2bzzx04802s7u

The version that was used was the Main 2018 AESC User Interface. Rhode Island must be chosen as the Region.

- Columns AA-AD – Capacity DRIPE (Bid capacity/Cleared) - Calculation for Use in Estimating Benefit #709 – Cells AJ35-39 and AK36-40.

The Public Health values listed in Column M were not ultimately used. Rather, the latest EPA values/kWh for public health benefits of energy efficiency and renewable energy were used. The report is: Public Health Benefits per kWh for Energy Efficiency and Renewable Energy in the United States: A Technical Report, published by the U.S. EPA, May 2021-Second Edition. The information is on page 5, New England Region. The data from this report was entered in cell D300, D301, E300, E301 on Worksheet 5-Benefit Inputs.

Prepared by or under the supervision of: Wanda Reder

Division 3-27

The data requests numbered DIV 3-26 through DIV 3-30 pertain to AMF BCA Attachment H FINAL (Confidential)

Request:

For Excel file AMF BCA Attachment H FINAL (Confidential), Worksheet 5-Benefit Inputs, please provide the source for the Residential, Commercial and Industrial Rates ($2020/MWh) contained in cells C141, C146 and C151 and the Rate Increase per yr. contained in D141, D146 and D151. Have any non-bypassable charges been removed from these estimates of rates?

Response:

The source of the rates was the Department of Energy's Energy Information Administration EIA-861 Rates and Revenues report. The rate increase/year was derived using historical data from the same source and PPL Electric Utilities Corporation's ("PPL Electric") experience with rate increases between 2010 and 2020. The starting values were 2020 per kWh rates for residential and commercial customers. The rate increases were calculated analyzing Rhode Island's rate increases for the last 20 years and the rate increases experienced by PPL Electric. Ultimately, the values chosen were 50% of Rhode Island's average rate increase from 2010-2020.

Non-bypassable charges have not been directly removed from the estimates of rates. Also not included are any changes in energy prices such as the increase experienced by Rhode Island customers this past Fall.

Prepared by or under the supervision of: Wanda Reder and Flora Flygt

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Division 3-28

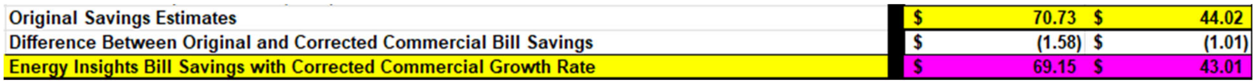
The data requests numbered DIV 3-26 through DIV 3-30 pertain to AMF BCA Attachment H FINAL (Confidential)

Request:

For Excel file AMF BCA Attachment H FINAL (Confidential), Worksheet 4 – RIEBenCalc, row 220, it appears that the estimate of future Commercial rates after the year 2025 is escalated at the assumed rate of Residential rates. Is this correct, and if so, why?

Response:

This is not correct due to spreadsheet error. The Commercial rates were incorrectly multiplied by the Residential growth rate of 1.65%. When the correct growth rate (.99%) is used, the value of the benefit is reduced by $1.58 million Nominal and $1.01 million NPV($2022), as shown below.



Original Savings Estimates	$ 70.73	$ 44.02
Difference Between Original and Corrected Commercial Bill Savings	$ (1.58)	$ (1.01)
Energy Insights Bill Savings with Corrected Commercial Growth Rate	$ 69.15	$ 43.01

Prepared by or under the supervision of: Wanda Reder and Flora Flygt

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Division 3-29

The data requests numbered DIV 3-26 through DIV 3-30 pertain to AMF BCA Attachment H FINAL (Confidential)

Request:

For Excel file AMF BCA Attachment H FINAL (Confidential), Please provide in executable format, the details of the ICE calculation of $11,892,393 for the annual value of faster notification benefits. Include all assumptions about model parameters and other inputs.

Response:

This response was provided in the Company's response to Division 1-17, which is attached to this response as Attachment DIV 3-29.

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-49-EL
In Re: Rhode Island Energy Advanced Metering Functionality Business Case and
Cost Recovery Program
Responses to the Division's First Set of Data Requests
Issued on January 6, 2023

Division 1-17

Request:

Please provide the data that supports a conclusion of a 22-minute faster outage response time for AMF meters on the PPL system, along with the associated ICE calculations for Rhode Island in executable format. Also, compare the average feeder length on the PPL system with the average feeder length on the RIE system.

Response:

To clarify, Rhode Island Energy did not calculate a benefit based on a faster "outage response" time; rather, the Company calculated the benefit based on a faster notification of an outage. This benefit is discussed on pages 145-146 of the AMF Business Case. The outage response time was assumed to be unchanged. With AMR meters, the Company becomes aware of an outage when the customer calls in to report it. With AMF, outage notification is automated through the "Last Gasp" feature. Because the notification is faster with automation from AMF, the duration of the outage that a customer experiences is shorter than it would have been had it taken longer to receive notification of the outage manually from a phone call. PPL Electric Utilities Corporation ("PPL Electric") tracks all outage notifications and their source. An analysis generated from PPL Electric's OMS system for over 15,000 outages from August 2019 through July 2020 where both Last Gasp messages and customer calls were received showed an average difference of 22.5 minutes between when the "Last Gasp" notification occurs and the customer call notification occurs.

As a result, the utility can respond to the outage 22 minutes earlier even though the "outage response time" does not change. Therefore, the 22 minutes is not calculated as part of SAIDI or CAIDI, but it is a period of time where the customer would experience a power outage with AMR that will be avoided with AMF.

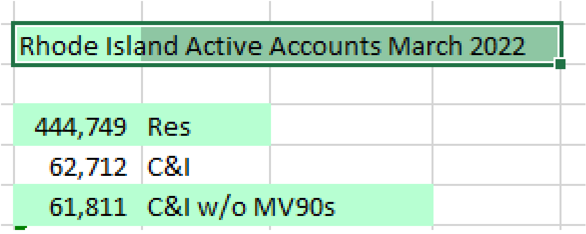
The Company used the Department of Energy's Interruption Cost Estimator ("ICE") to derive the customers' avoided cost of by reducing outages 22 minutes on average. The ICE calculator is available online at https://icecalculator.com. Attachment DIV 1-17, labeled ICE Calculator 22 minute Savings 040522, shows the calculations that were used to derive the benefits. Note that the average feeder length is not a variable in that was used in this analysis.

Prepared by or under the supervision of: Wanda Reder and Flora Flygt

Documentation – ICE Calculator
April 24, 2022

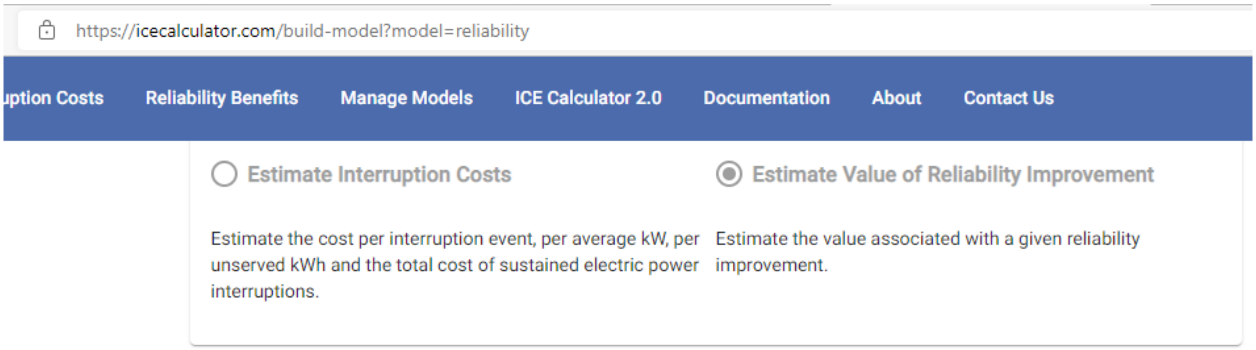
Assumptions:

1. Use latest counts of Rhode Island Active Accounts



Rhode Island Active Accounts March 2022	
444,749	Res
62,712	C&I
61,811	C&I w/o MV90s

2. 22- minute faster response time to outages.

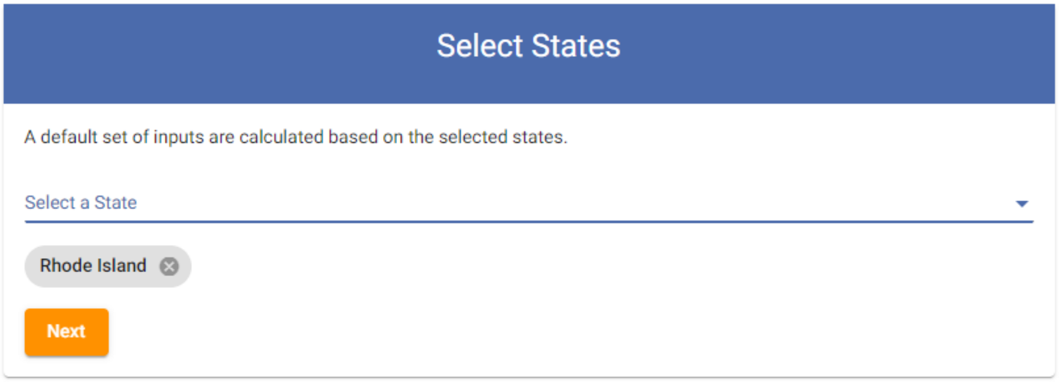


○ Estimate Interruption Costs

Estimate the cost per interruption event, per average kW, per unserved kWh and the total cost of sustained electric power interruptions.

● Estimate Value of Reliability Improvement

Estimate the value associated with a given reliability improvement.



Select States

A default set of inputs are calculated based on the selected states.

Select a State: Rhode Island

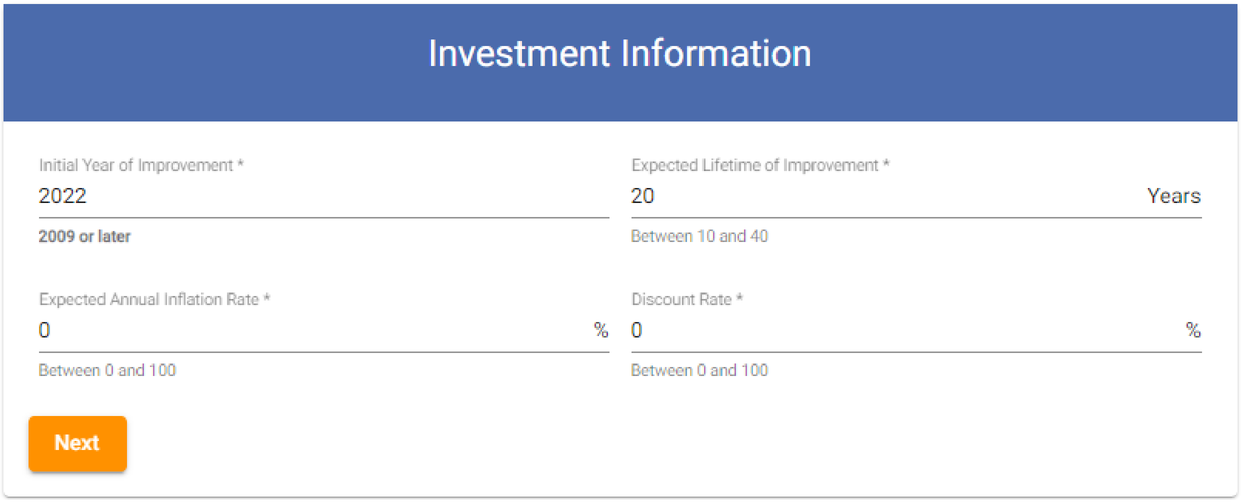
Number of Customers

Non-Residential *: 61,811

Between 0 and 10,000,000

Residential *: 444,749

Between 0 and 10,000,000



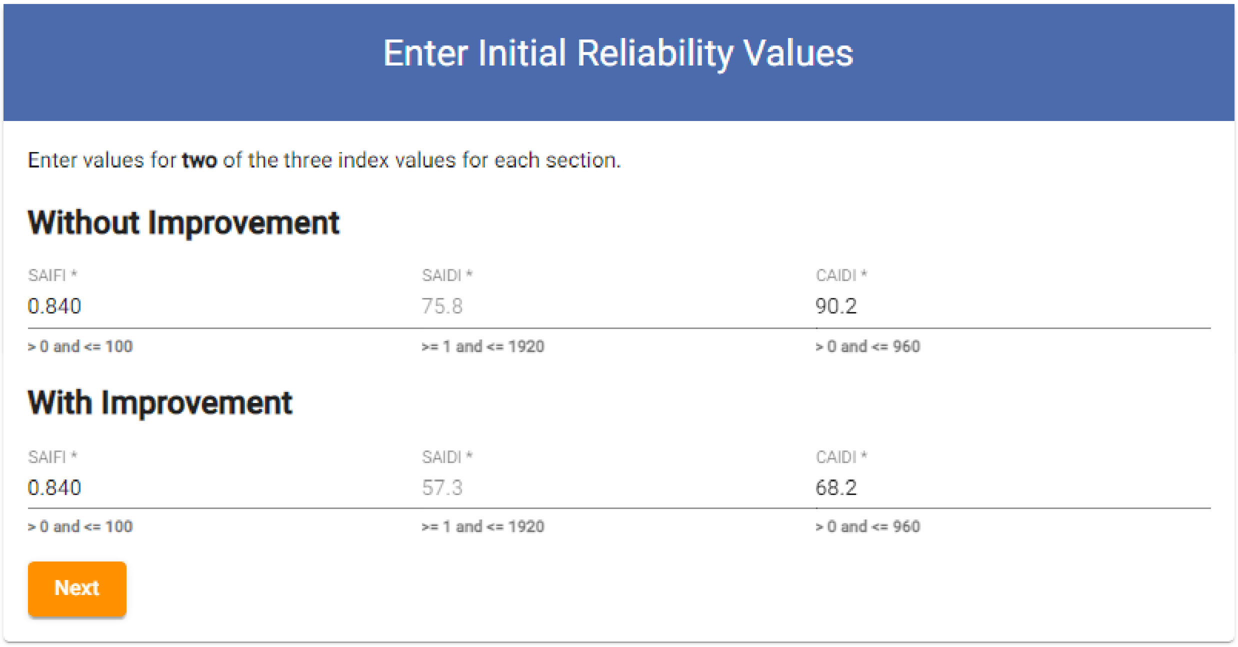
Investment Information

Initial Year of Improvement *
2022
2009 or later

Expected Lifetime of Improvement *
20 Years
Between 10 and 40

Expected Annual Inflation Rate *
0 %
Between 0 and 100

Discount Rate *
0 %
Between 0 and 100



Enter Initial Reliability Values

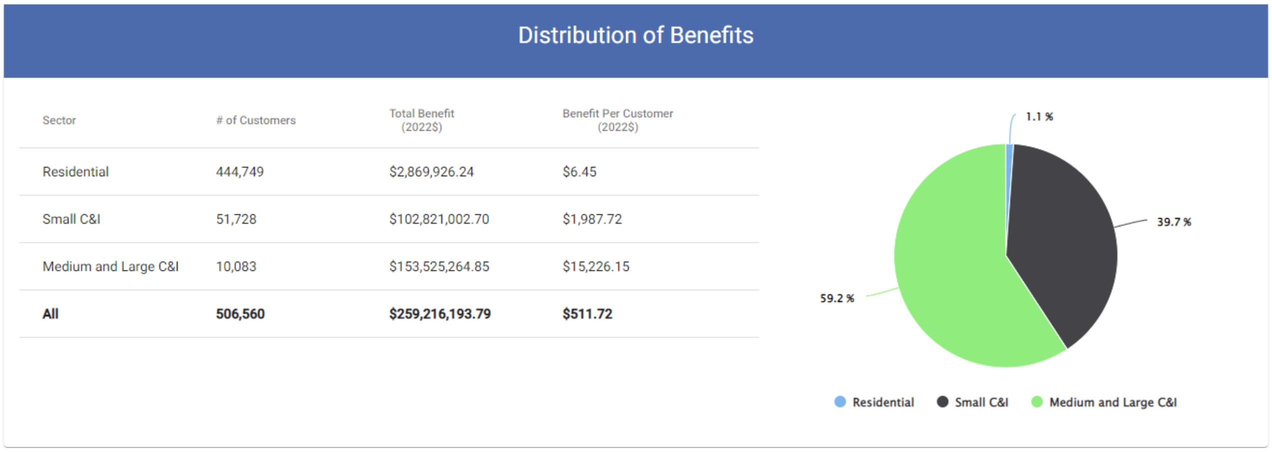
Enter values for **two** of the three index values for each section.

Without Improvement

SAIFI *	SAIDI *	CAIDI *
0.840	75.8	90.2
> 0 and <= 100	>= 1 and <= 1920	> 0 and <= 960

With Improvement

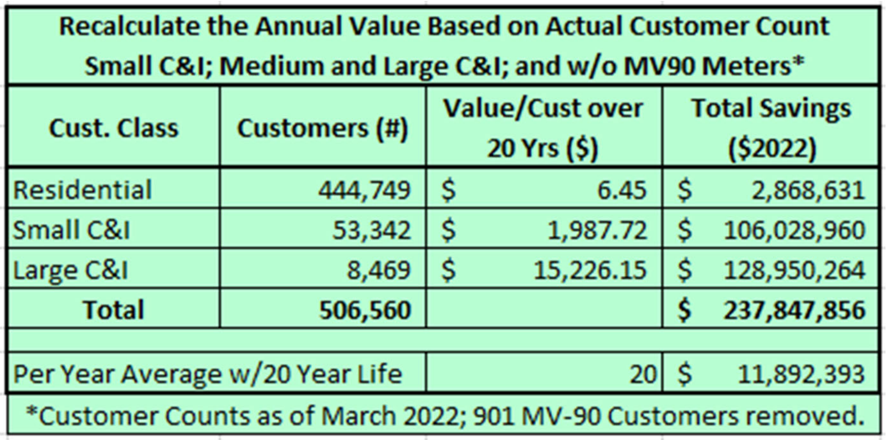
SAIFI *	SAIDI *	CAIDI *
0.840	57.3	68.2
> 0 and <= 100	>= 1 and <= 1920	> 0 and <= 960



Distribution of Benefits

Sector	# of Customers	Total Benefit (2022$)	Benefit Per Customer (2022$)
Residential	444,749	$2,869,926.24	$6.45
Small C&I	51,728	$102,821,002.70	$1,987.72
Medium and Large C&I	10,083	$153,525,264.85	$15,226.15
All	**506,560**	**$259,216,193.79**	**$511.72**

Calculation of Benefits Used in BCA:



**Recalculate the Annual Value Based on Actual Customer Count
Small C&I; Medium and Large C&I; and w/o MV90 Meters***

Cust. Class	Customers (#)	Value/Cust over 20 Yrs ($)	Total Savings ($2022)
Residential	444,749	$ 6.45	$ 2,868,631
Small C&I	53,342	$ 1,987.72	$ 106,028,960
Large C&I	8,469	$ 15,226.15	$ 128,950,264
Total	**506,560**		**$ 237,847,856**
Per Year Average w/20 Year Life		20	$ 11,892,393

*Customer Counts as of March 2022; 901 MV-90 Customers removed.

Division 3-30

The data requests numbered DIV 3-26 through DIV 3-30 pertain to AMF BCA Attachment H FINAL (Confidential)

Request:

The State of Rhode Island has adopted Climate Mandates for 100% renewables by 2033 and 0 carbon emissions by 2050. Has RIE factored in the reduced carbon per MWh of energy produced when it developed its estimates of expected benefits from non-embedded CO2 from its energy savings VVO/CVR integration, Energy Insights and other benefits previously estimated by National Grid?

Response:

Rhode Island Energy did not specifically factor in the reduced carbon per MWh of energy produced that would be attributed to the adopted climate mandates for 2033 and 2050. The Company used the values for Avoided Non-Embedded CO2 values in Rhode Island from the AESC 2021 Report and User Interface developed by Synapse Energy Economics to calculate reduced CO2 that would be attributable to the installation of AMF meters.

Prepared by or under the supervision of: Wanda Reder

Division 3-31

The data requests numbered DIV 3-26 through DIV 3-30 pertain to AMF BCA Attachment H FINAL (Confidential)

Request:

Please provide the estimated number of customer site visits by year associated with customer disconnects/connects from 2000 to the end of 2022.

Response:

Pursuant to the Transition Services Agreement, National Grid USA ("National Grid") provided Rhode Island Energy with the number of site visits associated with customer disconnects and connects for the previous thirteen years based on the data available in National Grid's systems as per the charts below. See the Company's response to Division 3-23 for definitions of category types. National Grid could not provide the data prior to fiscal year ("FY") 2010 because of department organizations and systems changing over the years. Resource Coordination functions, which were used to summarize this data into categories, did not exist prior to FY 2018; therefore, National Grid needed to map old systems to these standard codes. Counts during FY2021 and FY 2022 were reduced due to the Covid pandemic because the Company was unable to perform Turn-Off – Non-Payment work and there were fewer field calls in general.

3-31 - Disconnects & Reconnects **JOBS QUANTITY**

DESCRIPTION	FY10	FY11	FY12	FY13	FY14	FY15
EMERGENCY INVESTIGATIONS - NO ELECTRIC SERVICE, ABNORMAL VOLTAGE	2,272	1,560	1,070	967	905	1,118
TURN OFF - METER (METER - OFF/LOCKED)	10,350	9,744	8,694	8,080	8,679	7,141
TURN ON - METER	41,472	41,632	34,301	26,212	27,268	32,213
TURN OFF - NON-PAYMENT	49,362	40,462	31,428	20,576	19,766	28,537
INSTALL/REMOVE - METER	3,025	2,882	3,136	3,833	3,186	3,399

3-31 - Disconnects & Reconnects **JOBS QUANTITY**

DESCRIPTION	FY16	FY17	FY18	FY19	FY20	FY21	FY22
EMERGENCY INVESTIGATIONS - NO ELECTRIC SERVICE, ABNORMAL VOLTAGE	1,255	1,172	1,446	1,792	1,155	237	576
TURN OFF - METER (METER - OFF/LOCKED)	7,388	6,038	5,928	6,319	5,163	968	1,336
TURN ON - METER	32,556	33,074	28,556	26,158	23,162	4,237	10,829
TURN OFF - NON-PAYMENT	34,901	19403	42,397	43,462	43,782	91	7341
INSTALL/REMOVE - METER	3,977	3,814	4,168	5,638	3,359	2,971	3,385

Prepared by or under the supervision of: Philip J. Walnock