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When the wind doesn’t blow: The limits of intermittent resources and battery storage in the decarbonization of New England’s power system under increased electrification

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ABSTRACT

An important strategy for New England states to meet greenhouse gas reduction targets is increased electrification of transportation and residential heating alongside the expansion of intermittent wind and solar electric generation resources. Large-scale battery storage is investigated to shift temporally generation from when it is produced to when it is needed due to multi-day renewable resource production declines. Firm generation resources or a technology breakthrough is needed to meet demand during these multi-day periods.

1. Introduction

New England’s largest states are poised to significantly increase the supply of off-shore wind (OSW) power resources and to continue pursuing the growth of adoption of photovoltaic (PV) power supplies. At the same time, most New England states recognize the role that electrification of transportation and building heating must play to be realistically on a trajectory that will reduce carbon dioxide emissions consistent with the region’s objectives.[1] The combination of increased supply of intermittent resources and reliance on electrification for transportation and building heating fundamentally changes the way the region’s power system will be utilized. Moreover, while these changes will result in a significant decline in CO_2 emissions, there still remains the unsettled question of what role existing gas-fired resources or a technological breakthrough may be needed to achieve the region’s objectives without burdening consumers.[2]

In this paper we examine a future scenario where we assume future increases in intermittent resource additions and transportation and building heating electrification in New England that puts the region on track to meeting its CO_2 emission reduction objectives. We then evaluate an additional large increase in OSW (9 GW) and 4-hour duration battery storage (10 GW) resources that would reduce CO_2 emissions nearly an additional 50 percent. Using the results of this analysis, we assess the hourly operational profiles that result for the battery storage and gas-fired resources and estimate the marginal cost of CO_2 emission reductions that are attributable to the additional battery storage resources. In particular, we isolate the gas-fired resource CO_2 emission reductions resulting from the storage resource additions and calculate the cost of these reductions based on the storage resource costs not otherwise covered by wholesale power market revenues.[3]

Our results reveal two key findings.[4] First, multi-day periods where intermittent resources are not producing significant output reveal that even with a large quantity of battery storage resources there is a short-term reliance on conventional gas-fired resources. It is important to note that in our analysis we assume that existing natural gas-fired generation resources continue to operate. Therefore, in our analysis, natural gas

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[1] The importance of electrification in meeting growing New England decarbonization objectives is examined in the forthcoming report: Cavicchi, J. and Hibbard, P., Carbon Pricing for New England, Context, Key Factors, and Impacts, Analysis Group

[2] The challenges of intermittent resource integration are also discussed in Cole and Frazier (2018), Dorsey-Palmateer (2019), Energy and Environmental Economics, Inc (2019), Golden et al. (2019), ISO New Engand (2016), Jenkens et al. (2018), Joskow (2019), Kemabonta et al. (2018), and Sepulveda et al. (2018).

[3] For other discussions of the role of storage in reducing emissions, see Geske and Green (2020), Khalilpour et al. (2018), Mahani et al. (2020), McLaren et al. (2019), Schmalensee (2019), Wadsack et al. (2018) and Ziegler et al. (2019).

[4] There have been numerous recent insights in modeling the costs and benefits of energy storage systems (see Hittinger and Ciez, 2020). Our contribution is to highlight the potential limitations of combining storage with intermittent resources when confronted with a multi-day absence of intermittent generation.

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generation can also be viewed as a placeholder for a technological breakthrough such as a longer-duration battery storage. Second, the estimated marginal cost of battery storage for reducing CO_2 emissions could be as high as \$1350 per short ton reduced. In other words, limited reliance on gas-fired resources does not significantly increase CO_2 emissions and the cost of replacing these resources with storage is extremely high. Moreover, in our analysis we assume a significant decline in battery storage cost relative to current costs. Absent a major technological breakthrough in storage technology, consumers would benefit from policies that support alternative approaches for reducing CO_2 emissions.

2. ISO-NE wholesale electricity markets with increased intermittent generation and large scale electrification

Achieving the greenhouse gas (GHG) reduction objectives in New England requires both significant growth in renewable energy generation resources and electrification of transportation, and eventually building heating systems. Increased reliance on electricity for transportation and heating fundamentally changes the daily and seasonal hourly electricity demand profile. The hourly demand profiles of the future will be served by a fundamentally different electric generation resource mixture. However, a generation resource mixture that increasingly relies on intermittent production requires careful analysis to understand future system operational requirements. The growth in electricity demand will not align with the production profiles of intermittent resources at all times and there will be extended periods where very little intermittent production is available. It is unclear what resource mixture will cost effectively perform during these periods of severely reduced production, but incurring significant costs for a very limited time period is unlikely to be cost effective.

2.1. Modeling assumptions

Our modeling approach combines the Enelytix security constrained unit commitment and hourly dispatch model for the ISO-NE electricity sector with electrification models that simulate changes in gasoline consumption, heating fuels, electricity demand and GHG emissions stemming from electrification of the transportation and heating sectors.[5] The baseline dispatch modeling analysis input data is primarily from ISO-NE's most recent 2019–2028 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report, 2019) and associated analyses that form the basis of the CELT Report. We rely on gas and oil futures markets data for near-term fuel prices and extend these prices using the 2019 U.S. Energy Information Administration Annual Energy outlook base case regional growth rates.

In order to meet the New England states' GHG emission reduction standards based on the combination of electrification and electric sector decarbonization, we assume that 75 % of residential homes heating with oil, propane, or natural gas as of 2019 switch to electric heating and 90 % of consumers driving light duty vehicles (LDV) as of 2019 switch to electric vehicles. We assume that Off-shore wind electric generation resource developments are completed consistent with current legislative and regulatory commitments (U.S. Offshore Wind Project Pipeline, 2020); 25 % greater energy efficiency investments than the annual growth of approximately 5–6 % based on ISO-NE's most recent forecast;[6] and installation of behind-the-meter (BTM) PV systems continues consistent with ISO-NE's most recent forecast.[7] In addition, to meet the states GHG goals, we add increased quantities of on-shore and off-shore wind, in-front-of-the-meter PV and storage resources, and a new transmission interconnection to access additional hydroelectric and zero carbon resources from Canada in 2035. These increased zero-emission resources are needed to accommodate the increased demand from greater electrification, and to maintain New England's progress toward meeting its GHG reduction standards. The first column of Table 1 below summarizes these additions.

Table 1
Summary of Capacity (MW) Assumptions Uses in ISO New England Electrification Scenarios.

	Baseline (MW)	Increased OSW and Storage (MW)
2025 Existing Derated Capacity After Retirements (Excludes BTM PV)	28,818	28,818
Assumed Additions (Derated Capacity)		
Solar Additions	1832	1832
Battery Storage Additions	2500	12,500
Onshore Wind Additions	364	364
Additional Canadian Interconnection	1090	1090
Offshore Wind Additions	1980	4680
2035 Installed Capacity (Derated Capacity)	36,585	49,285
Imports	1188	1188
2035 Total Capacity	37,772	50,472
Assumed Behind-the-Meter PV and Energy Efficiency		
Behind-the-Meter PV	1392	1392
Energy Efficiency in Peak Hour	10,311	10,311

Notes:
[1] Capacity represents the total existing capacity at the start of each year prior to adding additional resources. The total capacity accounts for behind-the-meter PV generation and improvements in energy efficiency. Onshore wind, offshore wind, and solar capacity is derated at factors of 26 %, 30 %, and 28.5 %, respectively. For additional detail, see CELT Report, 2019.
[2] Existing capacity as of 2035 includes approved renewable resource additions and expected or at-risk unit retirements of approximately 5500 MW of capacity of aging coal-, oil- and gas-fired generation stations.
[3] Between 2019 and 2035, 16,998 MW of capacity is expected to come online. These additions include approved offshore wind, the Canadian Interconnection, and others.
[4] Import capacity is obtained from the 2019 CELT Report.
[5] The *2016 Act to Promote Energy Diversity* directed Massachusetts electricity distribution companies to procure 1600 MW of offshore wind by 2027 (Commonwealth of Massachusetts, 2016). In May 2018, it was announced that the 800 MW Vineyard Wind project had been selected. The *2018 Act to Advance Clean Energy* authorizes state officials to procure an additional 1600 MW by 2035 (Commonwealth of Massachusetts, 2018).
[6] In June of 2019, the Connecticut state government passed *An Act Concerning the Procurement of Energy Derived from Offshore Wind* which enabled the Commissioner of Energy and Environmental Protection to issue solicitations totaling up to 2000 MW. All 2000 MW must be reached by the end of 2030 (State of Connecticut, 2020).
[7] In 2018, Rhode Island issued an RFP for 400 MW of offshore wind. In May 2018 it was announced they had selected Deepwater Wind's 400 MW Revolution Wind Project.
[8] We include the total quantity of battery storage in this tabulation, but do not assess whether the entire amount would be considered available as capacity market resources.

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[5] We used the Enelytix security-constrained unit commitment and hourly dispatch model for our analysis (Enelytix, Newton Energy Group LLC and Polaris Systems Optimization, Inc.). We do not model transmission constraints.

[6] ISO New England, Final 2019 Energy Efficiency Forecast, May 1, 2019. We base our longer-term growth assumptions on the middle years of ISO-NE's forecast 2023−2025.

[7] ISO New England, Final 2019 PV Forecast, April 29, 2019.

We take the scenario described above as a baseline scenario that would allow New England to meet its GHG emission reduction targets. We then develop a resource mixture that would result in an additional 50 % reduction of fossil fuel generation. We calculate that an additional 9 GW of OSW, coupled with 40 GWh of battery storage, with a minimum 4-hour discharge (10 GW), would allow New England to meet this more ambitious GHG emission reduction target.

2.2. *Impact of increased intermittent resource supply and vehicle and residential heating electrification*

The simultaneous growth in renewable resource penetration and electrification of transportation and building heating systems creates two distinct changes in the operations of the New England electric system. First, the electric system peak demand will move from the summer season to the winter season and the time of day when the peak is most likely to occur will correspond with heating demand as opposed to cooling demand. Second, the intermittency of wind and solar resources will create multi-day operational challenges as periods with little wind and solar generation must be met with firm generation resources. While neither of these operational changes would be expected to result in reliability problems, the cost to consumers of ensuring reliable power supply will vary considerably depending upon the future resource mixture.

Fig. 1 shows projected peak demands with substantial increases in electrification in light-duty vehicle transportation and residential heating and reveals two key implications for future electric system hourly demand shapes. First, the charging pattern of light duty electric vehicles (EVs) is likely to introduce large hourly load increases in the evening hours. Second, the major increase in electric heating and EV penetration will substantially increase base load during the winter months, eventually shifting the system peak demand from summer to winter. As Fig. 1 shows, the growth in the winter peak demand is substantial; even with aggressive additions of renewable resources the shift points to the ongoing need for existing fossil fuel resources to support reliable New England power sector operations as the region achieves aggressive reductions in GHG emissions.[8]

Fig. 2 shows an example of the impact of intermittent resource production decline that can occur during winter and shoulder season multi-day periods when skies are cloudy and wind speeds are low or practically zero.[9] During one of the typical three-day periods, we estimate a total of 990 GWh must be provided by dispatchable gas-fired resources. These reductions in intermittent resource production are not large relative to the annual or seasonal projected future demand, but they call for careful consideration as they are certain to occur occasionally.

Another important element of electrification relates to the increase in net load variability (net load is equal to total system load minus solar and wind-powered generation resources). As electrification increases, there will be hour-to-hour load variations that will require thousands of megawatts of resources available to ramp up and down over very short periods of time to accommodate changes in net load. For example, Fig. 3 shows that estimated system ramp in 2035 during January, the month with the highest average ramp. The results show that the ramp will be between 10,000 and 15,000 MW, depending upon both renewable energy production patterns and EV charging schedules. It is clear that a significant quantity of flexible generation resources will be necessary to accommodate the large variations in net load.[10]

2.3. *Projected generation resource mixture and CO_2 emissions*

Fig. 4 shows the projected monthly generation resource mixtures for 2035. The variation in the production of intermittent resources results in noticeable swings in the month-to-month reliance on gas-fired resources. While the overall reliance on gas-fired resources is substantially reduced (approximately 48 % lower relative to recent production levels) even with the substantial assumed increase in electrification due to the significant addition of renewable resources, these resources still play an important role in months with the lowest projected intermittent resource output.

Fig. 5 shows the projected CO_2 emissions reductions for the modeled 2035 resource mixture with assumed electrification. As the Figure shows the modeling results in substantial reductions in CO_2 emissions.[11] However, these reductions are driven in large part by the assumed electrification of LDV transportation and building heating systems. The projected power sector CO_2 emissions decline more modestly from 26.5 million metric tons in 2017 to approximately 19.1 million metric tons, but still a major decline relative to recently observed levels.

2.4. *Wholesale energy price impacts*

Fig. 6 shows the projected 2035 price duration curve and average system wide locational marginal price.[12] The significant increase in assumed intermittent resources results in over 1,100 hours with prices of zero, but still the vast majority of hours' prices are set by gas-fired resources which are projected to remain the marginal price setting resource well into the future. In addition, the continued reliance on a small amount of gas-fired generation is important for ensuring reliable system operations and continues to provide important wholesale energy price signals, especially during colder months.

3. Modeling results with increased OSW and battery storage

We then evaluate an additional large increase in OSW (9 GW) and 4-hour duration battery storage (10 GW) resources that would reduce CO_2 emissions an additional 50 percent. Using the results of this analysis, we assess the hourly operational profiles that result for the battery storage and gas-fired resources and estimate the marginal cost of CO_2 emission reductions that are attributable to the additional battery storage resources. In particular, we isolate the gas-fired resource CO_2 emission reductions resulting from the storage resource additions and calculate the cost of these reductions based on the storage resource costs not otherwise covered by wholesale power market revenues.

3.1. *Impact on system operations*

Economically meeting the growing ramping requirements requires

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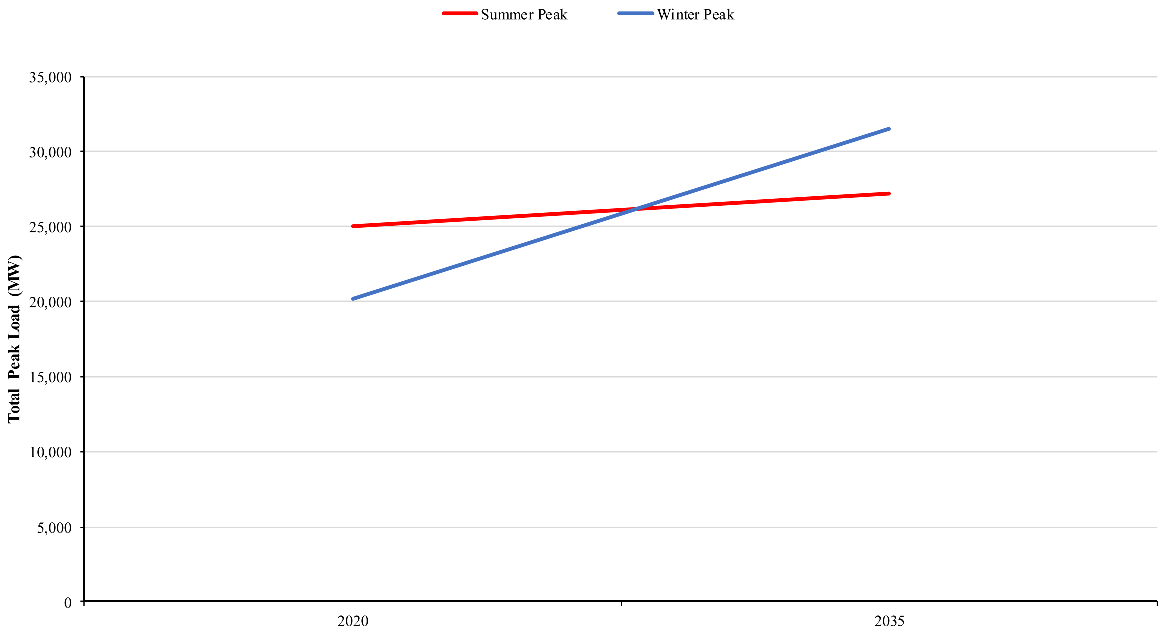
[8] Our analysis focuses on the starting point set of resources and decarbonization options that appear practically achievable based on current information. We acknowledge that this could change if there is a breakthrough in ubiquitous and economic energy storage or an alternative fuel source (e.g., hydrogen). However, absent significant technological change, the need for the region's infrastructure remains an important element of an economic transition and reliable system operations.

[9] Our analysis uses wind profiles from the National Renewable Energy Laboratory (NREL) for an offshore site off the coast of Massachusetts.

[10] In addition, the increased net-load variation implies that required operational reserves may increase. However, the potential for a larger reserve requirement will be a function of whether the impact of unforeseen system disruptions increasing materially as net-load variation grows. Intermittent resource forecasting improvements can be expected to minimize unexpected variation in net-load.

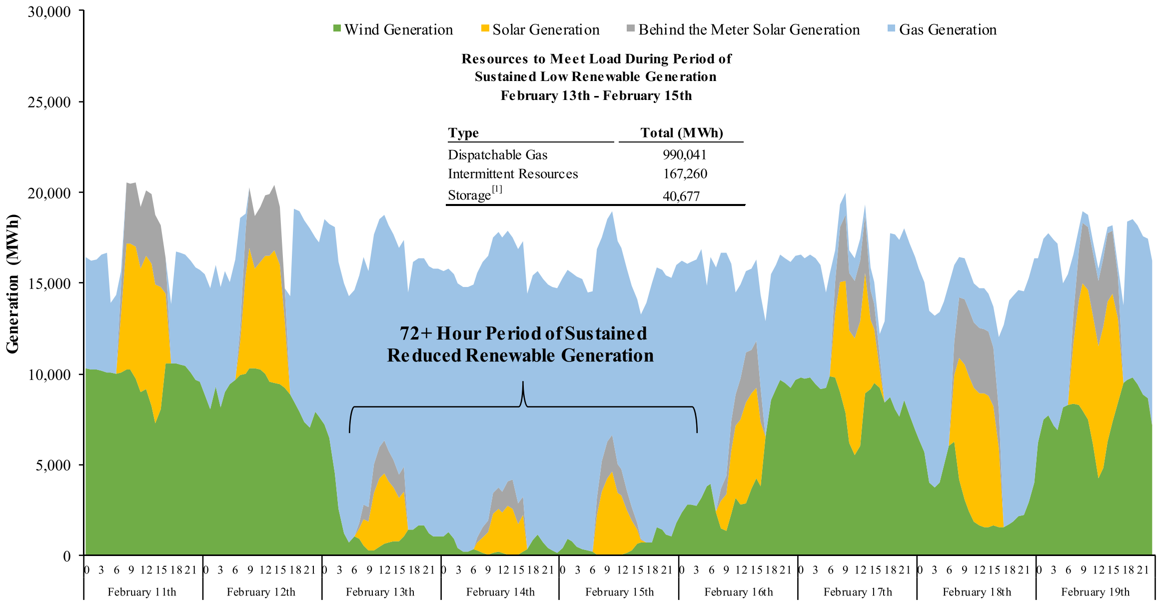
[11] The projected carbon dioxide emission level we find falls within the range that have been reported in other analyses. See, for example, Northeast States for Coordinated Air Use Management (NESCAUM), *Greenhouse Gas Mitigation Analysis for New England: White Paper Policy Summary*, September 2018, p. 4.

[12] We do not model the potential increased incidence of scarcity pricing that may result from the growing hourly system ramping requirements.



Notes:
[1] Assumes 75% of residential homes currently heating with gas, oil, or propane switch to electric heating. Additionally, it assumes 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. Finally, the scenario assumes additional EE (25% increase over assumed 2035 EE), and adds additional renewable resources.
[2] The winter peak is the coincidental peak load for January, February, and March after netting out behind-the-meter solar and adding electrification load. Similarly, the summer peak is the coincidental peak load for June, July, and August after netting out behind-the-meter solar and adding electrification load.
[3] ISO NE CELT forecasted 2020 load is net of behind-the-meter solar and energy efficiency.

Fig. 1. Change in Annual Peak Load by Season with Increased Electrification.



Resources to Meet Load During Period of Sustained Low Renewable Generation February 13th - February 15th

Type	Total (MWh)
Dispatchable Gas	990,041
Intermittent Resources	167,260
Storage[1]	40,677

Note:
[1] Between February 13th and February 15th, the wind capacity factor is 9.3%. For the same period, the PV capacity factor is 10.5%.

Fig. 2. Intermittency of Wind and Solar Resources.
February 11th – February 19th.

the operation of conventional resources for many years into the future. The projected seasonal resource operational profiles show the expected average diurnal hourly usage patterns for dispatchable resources (See Fig. 7). The battery storage resources' average hourly charging and dispatch patterns show charging consistently occurs during daylight hours when energy prices are consistently at their lowest values. As Fig. 7 shows, the discharge patterns show the need for energy both in overnight and evening hours. The variations across seasons reveal notable differences in the magnitude of the average hourly storage quantities which are much greater in the spring and winter (peaking at around 5000 MW) and with a charging profile that exhibits a noticeable peak in the mid-afternoon.

Moreover, the battery discharge patterns reveal that these resources need to follow a daily schedule that allows for charge to be carried over from one day to the next. In other words, their usage is not fully optimized if the discharge cycle results in the resource being fully

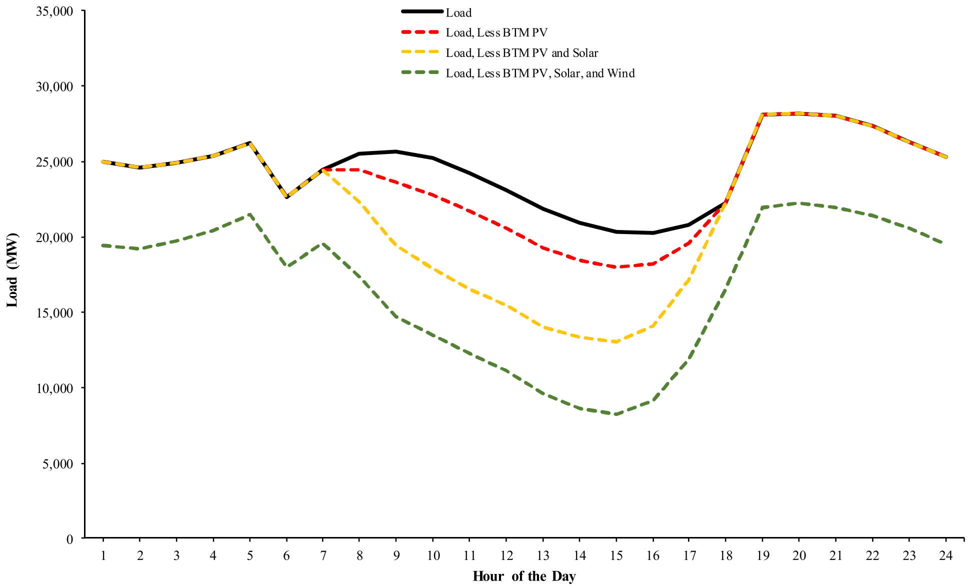
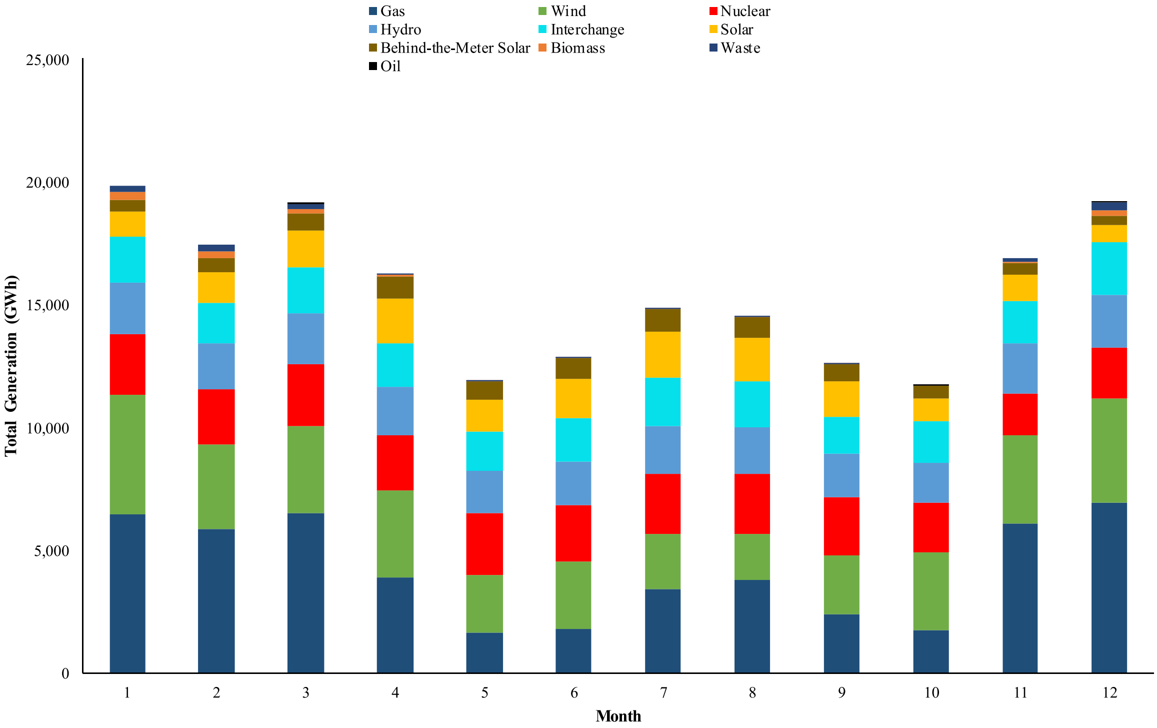


Fig. 3. January Average Ramp-Up.



Source:
[A] Enelytix Modeling Results.

Fig. 4. Projected 2035 Total Monthly Generation Resource Mixture.

discharged at the end of a day.[13] The growth in energy demand – especially for residential heating – results in these resources discharging in the early morning hours and then recharging during the daylight hours. In addition, storage resources significantly contribute to managing system ramping requirements by charging at times when solar resources ramp up and discharging when these resources ramp down.

Fig. 8 shows the projected average hourly operational pattern of gas-fired resources in the presence of additional wind and storage. The operational profile of gas-fired resources is flat and its average shape varies very little across seasons. The most efficient gas-fired resources operate regularly with more capacity operating in the winter and spring seasons. However, there are isolated instances where all available gas-fired resources are projected to operate indicating these resources will

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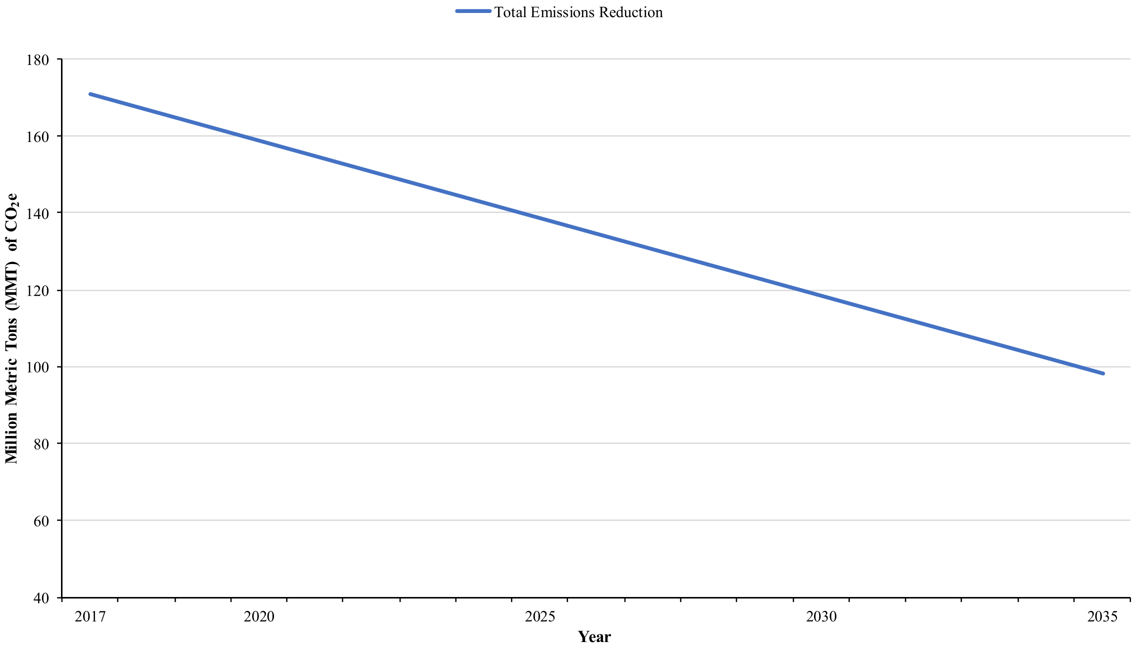
[13] In our modeling analysis, the battery optimizes over a 72 hour planning horizon, with a rolling horizon that starts at hour 24 each day. This allows the modeling to capture the need for storage resources to be available in early morning hours and capture periods where holding storage for multiple day discharges is optimal. We specified a battery state of charge of 50% for the beginning of each horizon. However, due to the rolling horizon, the storage level is often different than 50% at each hour 0.



Notes:

[1] In 2015, total GHG emissions across New England were 177.3 MMT of CO_2e (43.8 in CT, 76.1 in MA, 19.1 in ME, 17.0 in NH, 11.3 in RI, and 10.0 in VT).

[2] Economy-wide emission reduction goals are determined by aggregating each New England state's historical emissions and annual emission targets. If data is unavailable for a given year, the goal is estimated by interpolating results from years where it is available by state.

[3] Resource mixture adjustments include the retirement of fossil-fuel plants and the addition of renewable resources.

[4] This analysis assumes that in 2035, 75% of residential homes currently heating with gas, oil, or propane switch to electric heating and that 90% of consumers driving light-duty vehicles switch to electric vehicles. It also assumes additional energy efficiency (EE) at a 25% increase over assumed 2035 EE, and adds additional storage and zero-emission resources, needed to accommodate increase electrification and maintain New England's progress towards meeting its carbon reduction standard.

Fig. 5. Projected 2035 CO_2 Emission Reductions.

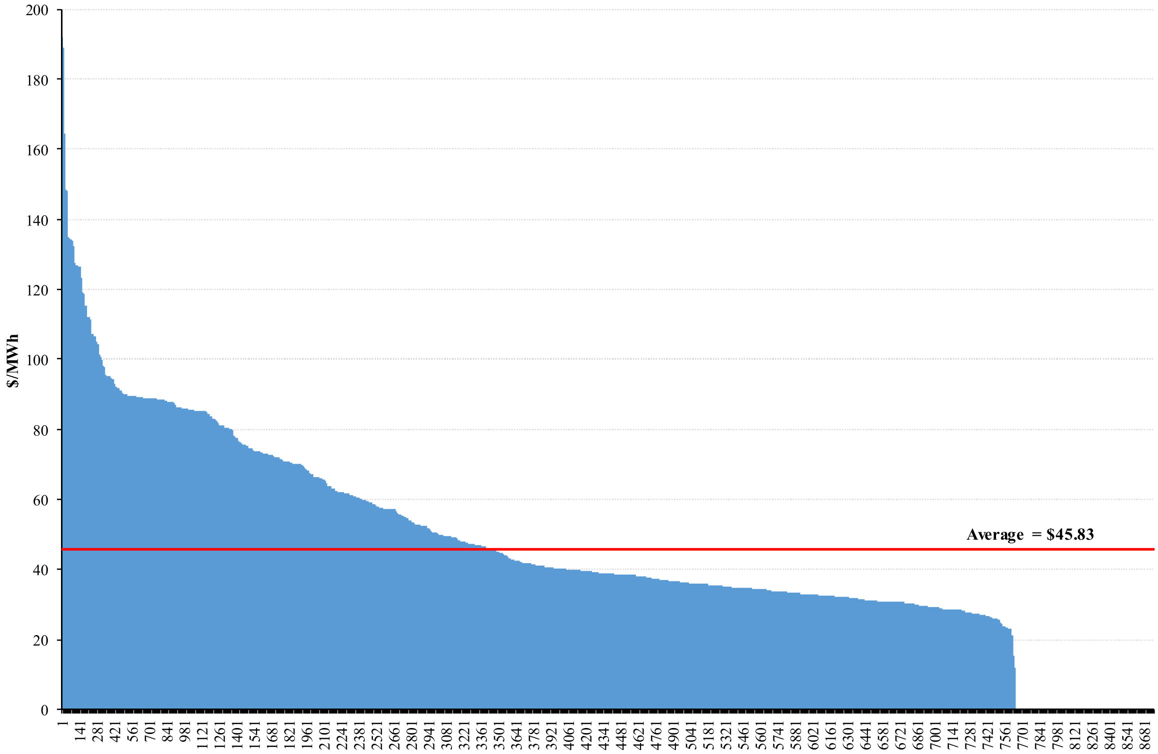


Fig. 6. 2035 Projected Price Duration Curve.

continue to play a critical role to maintain reliable system operations.

In particular, during winter and shoulder season periods where intermittent resource output can be extremely low, even 10 GW of 4-hour duration battery storage would fall well short of being able to bridge a multi-day period of reduced renewable production (See Figs. 9 and 10). There are three takeaways from this pattern of gas and intermittent generation. First, comparing Figs. 9 with 2, the latter of which depicts the same time period without the added OSW and storage, gas is no longer needed to meet the load on days with high levels of wind and sun.

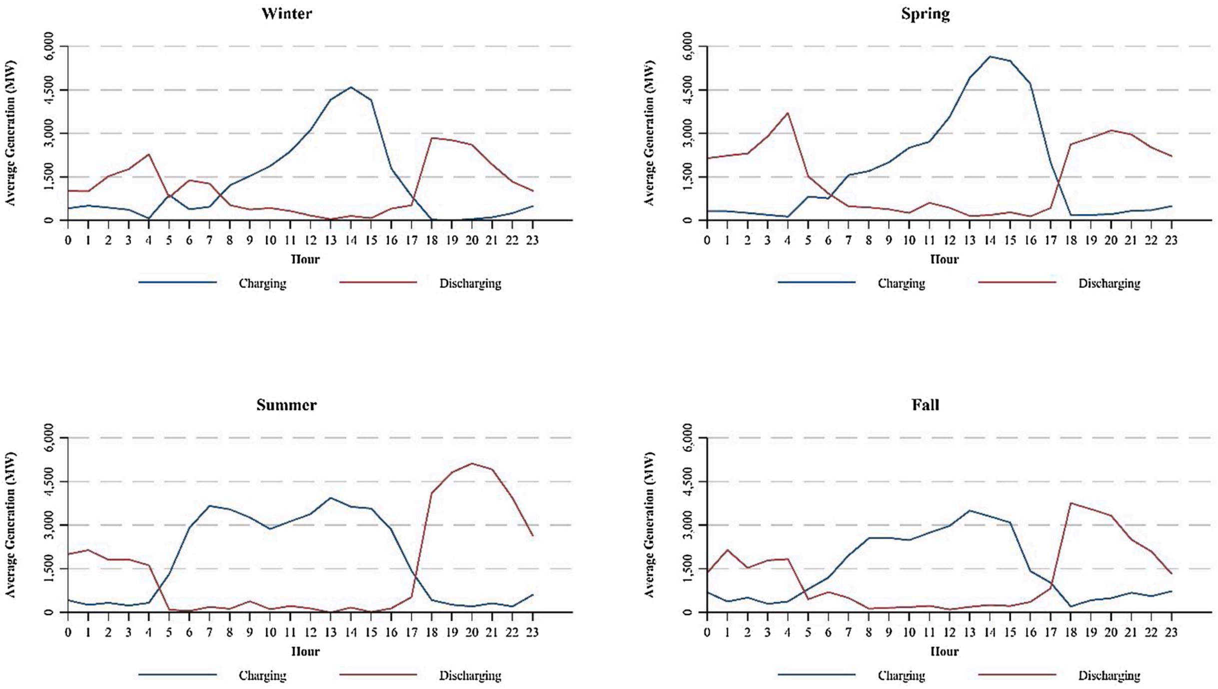


Fig. 7. 2035 Projected Average Hourly Seasonal Battery Charge and Discharge Schedules.
Winter is defined as Dec.-Feb., Spring is March-May, Summer is June-August, and Fall is Sept.-Nov.

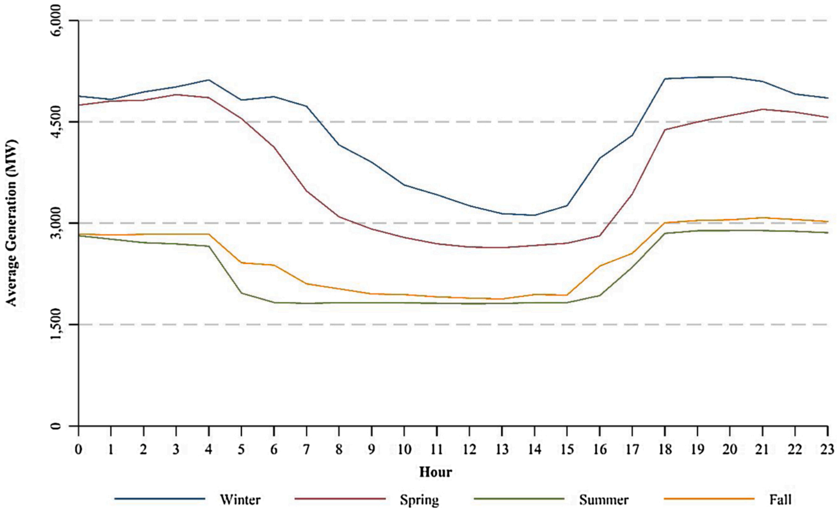
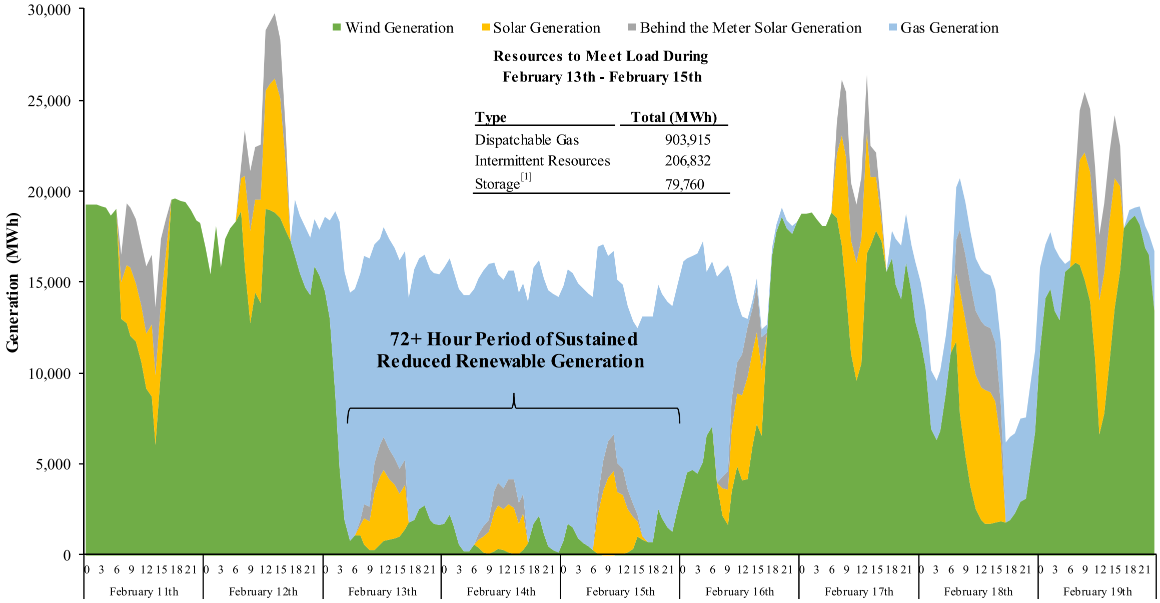


Fig. 8. Projected 2035 Average Hourly Seasonal Gas Generation.

Second, we can see in Fig. 9 that during the 72 hour period of sustained reduced renewable generation the load is still met by dispatchable gas resources. Thus, while storage provides additional energy due to the ability to charge it economically during this time period of reduced intermittent supply, it does not reduce the amount of gas-fired production as the system is short of energy, not capacity. Moreover, during this 72 hour period of sustained reduced renewable generation we observe 904 GWh of gas-fired resources are needed to meet the load, which is only 9% lower than the 990 GWh needed prior to the addition of OSW and battery storage (see Fig. 2). At the same time, Fig. 10 shows that the battery storage availability drops considerably during this period.

Third, we can see in Fig. 9 that during a short period of reduced renewable generation in the evening and early nighttime hours on February 18th, very little gas-fired production is needed compared with the same period in Fig. 2. This occurs because the battery storage can help meet the load during brief cloudy periods where wind speeds are low or practically zero. This can be seen in Fig. 10 where the battery storage is able to charge during the morning of February 18, and then discharge completely during the brief lull in wind in the early nighttime hours, before the wind picks up after midnight. This demonstrates how the battery storage can reallocate renewable energy over time, reducing reliance on dispatchable resources during a short-term reduction in intermittent generation. However, during multi-day periods, the battery storage cannot recharge, and, absent a technological breakthrough, significant amounts of dispatchable resources are required.

Finally, we recognize there are siting and operational implications



Note:
[1] Between February 13th and February 15th, the wind capacity factor is 5.4%. For the same period, the PV capacity factor is 6.2%.

Fig. 9. Intermittency of Wind and Solar Resources.
Increased OSW and Battery Storage.
February 12th – February 19th.

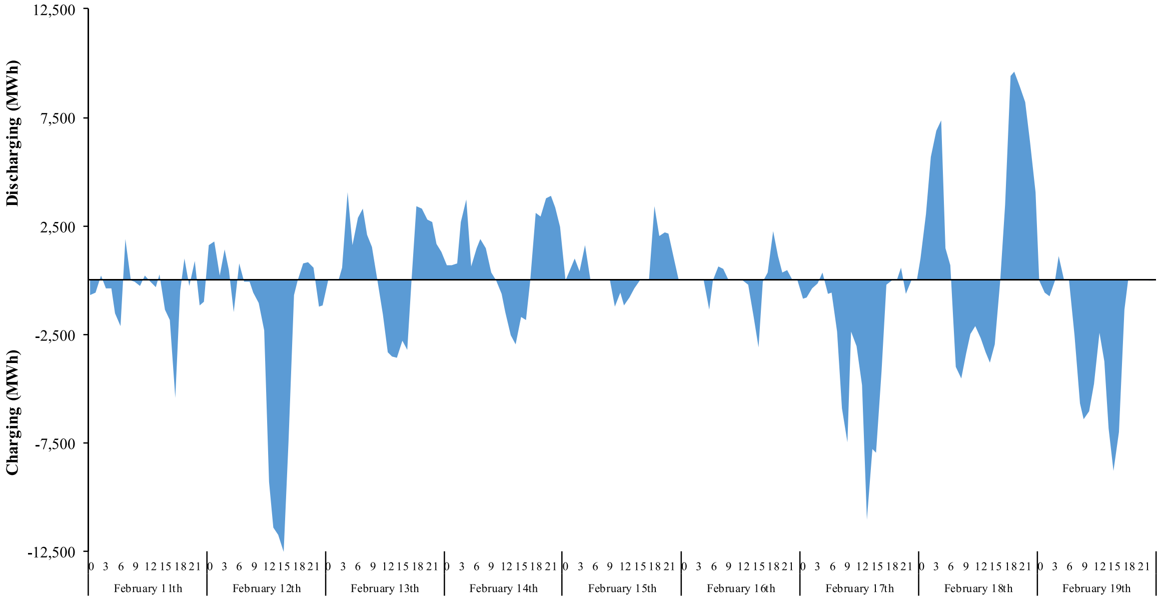


Fig. 10. Battery Storage Generation Profile.
Increased OSW and Battery Storage.
February 12th-February 19th.

associated with assuming the addition of 40 GWh of battery storage. We estimate that several hundred acres of land will likely be needed to accommodate massive growth in battery storage.[14] While it is reasonable to expect sufficient land would be available, it is unclear how easily the existing transmission system would accommodate such growth. In addition, the operational cycles for the batteries will need to be less restrictive as designing systems with one charge/discharge cycle per day does not allow for the storage systems to optimize charging and discharging hours. It will be critical that charging consistently occurs during the lowest price hours and that discharging be available over several hours.

3.2. Prices

Fig. 11 shows a comparison of the price duration curves for the two

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[14] We note that a recently planned Tesla installation required approximately 6 acres for 1GWh of battery storage (access at: https://electrek.co/2020/02/27/tesla-1gwh-megapack-battery-project-pge-approved/).

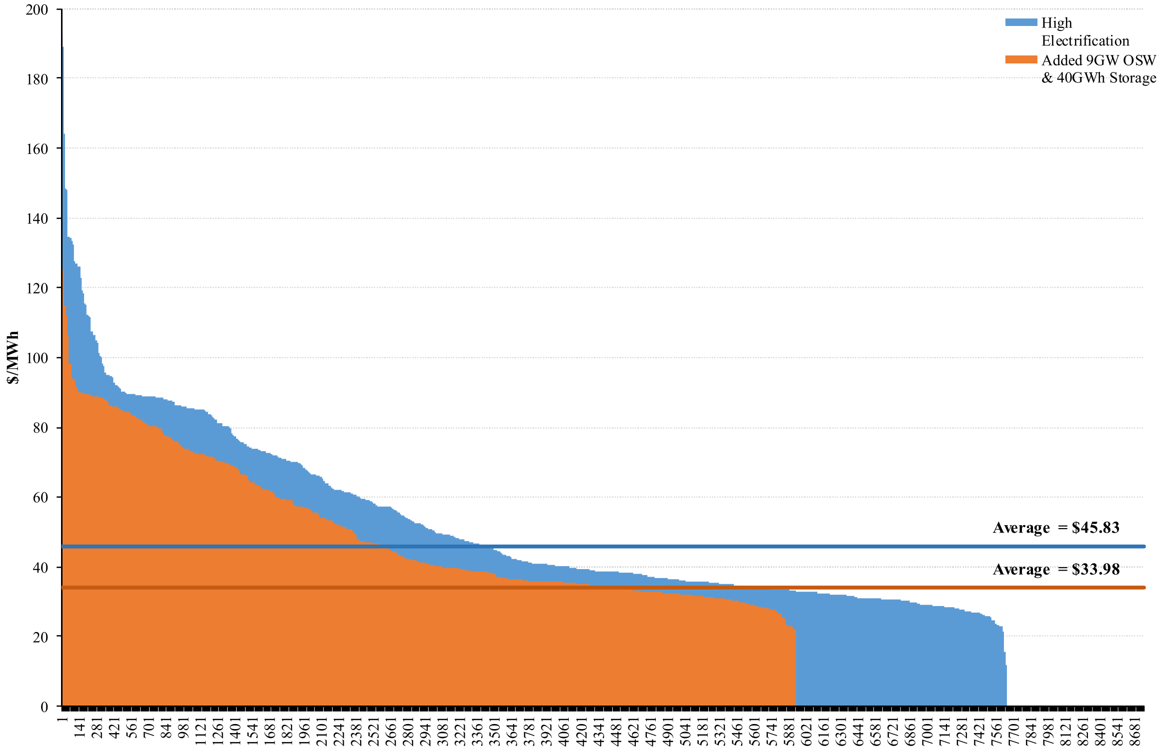

Fig. 11. Comparison of Projected Price Duration Curve.

modeling cases. With increased OSW the number of zero priced hours grows significantly and reduced reliance on fossil-fuel fired resources also puts downward pressure on prices as the least efficient generating units are operated less frequently. The average annual energy price declines by $11.85/MWh. In addition, we note that the average energy market margin for the battery storage resources is less than $15/MWh, representing a decline of $3.50/MWh relative to the base case.

3.3. *Emissions*

Fig. 12 shows the amount of CO_2 emissions from the electricity sector under the high electrification scenario, with the 9 GW of OSW but no 40 GW h battery, and finally with both the 40 GW h battery and 9 GW of OSW. Overall, adding 9 GW of OSW and the 40 GW h battery reduces emissions by just short of 50 %. About a sixth of this reduction[15] is due solely to the battery as it reduces curtailment from renewable resources.[16]

3.4. *Estimated cost of battery storage to reduce CO_2 emissions*

We estimated the marginal cost of reducing emissions of CO_2 from the 40 GW h battery by combining results of the modeling[17] with levelized projected costs of battery storage resources based on Lazard (2019) and an assumed revenue range from capacity market sales. Our projected 2035 levelized cost is $275/MWh, modeling market margins are $15-$30/MWh (including operating reserves revenues) and we assume capacity revenues with a range of $2.5/kW-month to $5/kW-Month.[18] We find that the net cost of CO_2 emission reductions ranges from $500/short ton reduced to as high as $1400/short-ton reduced, with the lower value assuming scarcity pricing and the higher capacity price, while the higher level assumes no scarcity pricing and the lower capacity price.

4. Conclusion

The results of these analyses show there can be major challenges to relying on battery storage resources in a future where winter electricity demand is significantly increased and available energy from intermittent resources is at seasonal lows. In the absence of available low cost intermittent resources, which often occurs multiple times during a weather-normal year in New England, batteries cannot be charged. Our analysis demonstrates that reliable electric system operation requires some type of dispatchable technology. In the absence of a technology breakthrough, it would not be surprising if gas-fired resources remain a cost-effective resource used significantly, on limited occasions during periods of the year when intermittent resource production is limited over a multi-day period. The costs of maintaining these resources is far less than the cost of a massive build out of energy storage resources and can benefit greatly from existing resources largely located in regions where they are well situated to balance intermittent resource output variability (e.g., southeastern New England).[19]

Moreover, it would be misguided to assume that massive storage

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[15] This share is similar to a study investigating the decarbonization impacts of renewables and storage in Texas and California (Arbabzadeh et al., 2019).

[16] For example, the addition of battery storage results in reduction in the curtailment of 9 GW of OSW of a little more than 2% (11.5% to 9.4%). Note OSW curtailment is minimal in the baseline high electrification case (1.8%).

[17] In our modeling, the battery takes advantage of arbitrage opportunities to generate revenue (see, for example, Salles et al., 2017). In addition, because we assume a substantial increase in battery capacity we do not assume material additional revenue streams are available in association with the potential for improving transmission and distribution system reliability.

[18] We do not assess the long-term impact on New England's forward capacity market and instead assume a wide range of possible capacity prices. Our assumed capacity prices imply costs for maintaining existing gas fired generation of $0.5–1 billion per year; far less than the several billion dollars per year needed to finance storage installations.

[19] For a discussion of the costs of energy storage resources, see Cole and Frazier (2019), EIA (2019), Ralon et al. (2017).

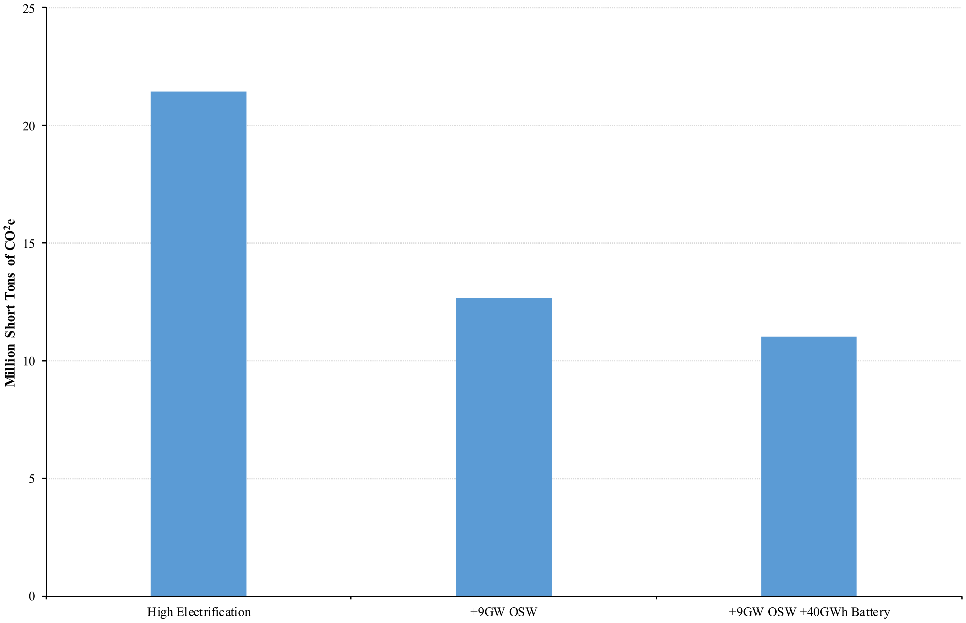

Fig. 12. Electricity Sector Emissions Under Modeled Scenarios.

additions would allow for cost-effective reductions in CO_2 emissions without a major technological breakthrough in storage duration. Those periods where demand will be the highest in the future are aligned with when intermittent resource output can be expected to be extremely low. However, the CO_2 emissions that result from running gas-fired generation during these short time periods is relatively low. Spending heavily on a technology that cannot deliver greater operational security is a poor use of financial resources.

Finally, it is clear that improved retail rate structures are critical to minimize the long-term cost of resources that will be necessary to rely heavily on electrification to reduce GHGs. Ensuring that the demand to meet increased use of electric vehicles and electric heating overlap minimally and avoid any unnecessary peaks will reduce the occasional reliance on gas-fired resources and help to minimize costs. Consumer responsiveness to retail electricity prices will be a key factor in moderating the impact of reliance on electrification to reduce emissions of greenhouse gases.

Declaration of Competing Interest

The authors report no declarations of interest.

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