

# Leveraging rail-based mobile energy storage to increase grid reliability in the face of climate uncertainty

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Maintaining reliability is increasingly challenging for electric grids as they endure more frequent extreme weather events and utilize more intermittent generation. Exploration of alternative reliability approaches is needed to effectively address these emerging issues. Here we examine the potential to use the US rail system as a nationwide backup transmission grid over which containerized batteries, or rail-based mobile energy storage (RMES), are shared among regions to meet demand peaks, relieve transmission congestion and increase resilience. We find that RMES is a feasible reliability solution for low-frequency, high-impact events and quantify its cost effectiveness relative to reliability-driven investments in transmission infrastructure and stationary capacity. Compared to new transmission lines and stationary battery capacity, deploying RMES for such events could save the power sector upwards of US\$300 per kW-year and US\$85 per kW-year, respectively. While no known technical barriers exclude RMES from grid participation, addressing interconnection challenges and revising regulatory frameworks is necessary for deployment at scale.

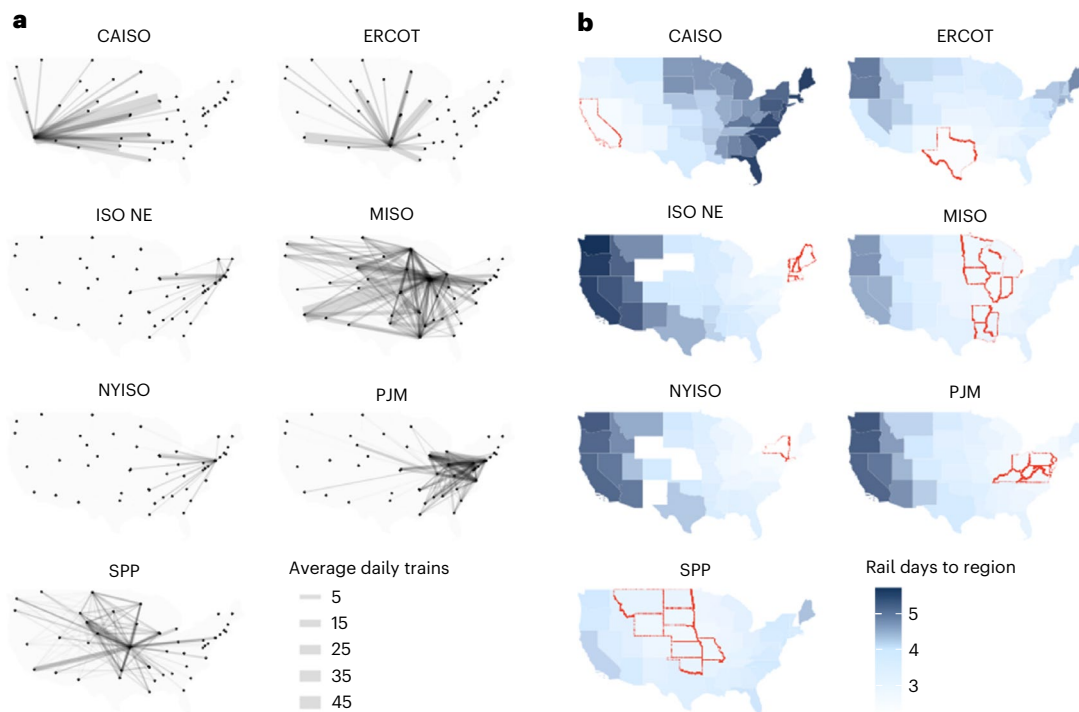
As the economy decarbonizes amid more frequent extreme weather events, the electric grid must simultaneously deploy zero-carbon generating resources, maintain reliability and become more resilient to major disruptions. Though electric reliability—the ability to maintain power delivery to customers in the face of routine uncertainty in normal operating conditions<sup>1</sup>—has long been a challenge, heightened supply uncertainty from renewable generation<sup>2</sup> and fundamental changes in electricity demand add considerable complexity<sup>3,4</sup>. Further, climate-driven weather extremes challenge the grid's resilience<sup>5</sup> or its ability to absorb, adapt to and recover from low-probability, high-impact disruptions<sup>6</sup>. Electric reliability and resilience will become increasingly important as the United States and other countries continue to pursue electrification to realize economy-wide decarbonization.

Electric reliability hinges on resource adequacy: the availability of electric power supply to serve demand (load), plus a reserve margin, in all hours and in each operating region. Resource adequacy addresses

future supply and demand uncertainty by providing a safety net of additional available capacity to serve load<sup>7</sup>. Historically, this safety net has been provided by investment in peaker plants: typically inefficient, fossil-fired combustion turbines with low capital costs and high operating costs. But this approach is becoming untenable as risks to the grid evolve. Uncertainty in supply/demand fluctuations is growing alongside more unpredictable weather and dependence on intermittent renewable generation<sup>8</sup>; further, the types of event that are stressing the grid are getting both more varied and more extreme (that is, falling outside 'normal' ranges)<sup>9</sup>. The practice of considering resource investments based on historical performance under normal conditions does little to address these risks.

A single electric operating region may face an extreme heat event, extreme cold event, renewable generation drought and/or a major storm<sup>10,11</sup>. Such uncertainty and variability could make it increasingly expensive and difficult to withstand and recover from these events. First, the heterogeneity and intensity of these risks may result in a

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**Fig. 1 | Estimated nationwide availability of freight rail. a**, The average daily number of freight trains travelling from each state in the contiguous United States into each grid operating region, or ISO. The width of the grey line increases with the number of daily freight trains. Most ISOs already have daily trains moving between them; for ISOs without direct connections, many have shared secondary connections (for example, California and New York, with their

own ISOs, are connected by Illinois). **b**, Average estimated time to move trains between ISOs; including scheduling time, moving trains between ISOs would probably take 1–6 days. The red lines represent the boundaries of each ISO. The blue shading depicts the estimated travel time to each ISO from each state. Basemaps provided by the US Census Bureau<sup>79</sup>.

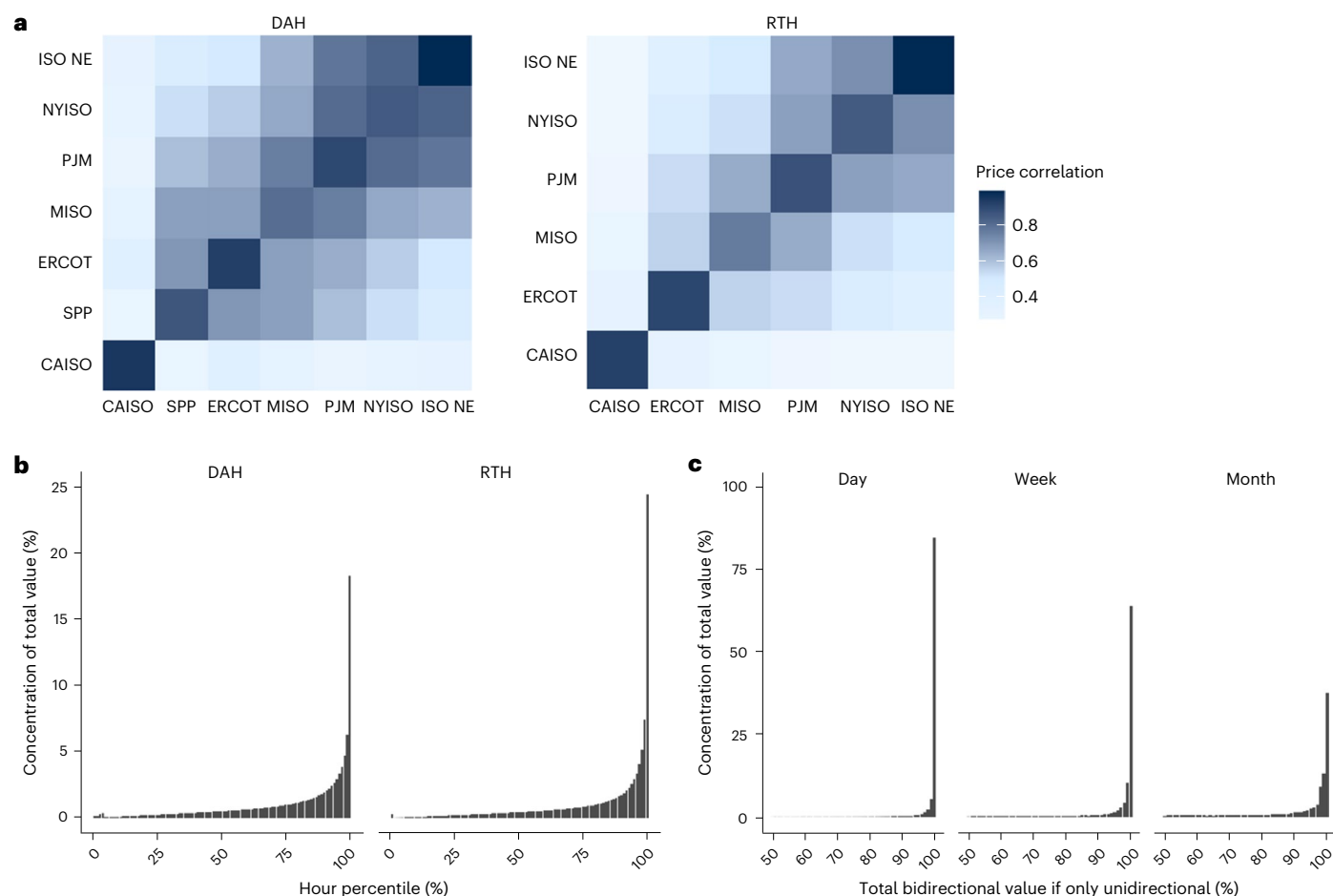
large portfolio of diverse (and sometimes duplicative) resource investments intended to address them<sup>6</sup>. For example, the investment strategy needed to mitigate a two-day extreme heat event in summer may differ from that needed to mitigate a two-week-long wind-generation drought in winter. Second, deep uncertainty around each event's probability, duration and location<sup>12,13</sup> makes it difficult to prioritize, site and evaluate the efficacy of each investment. Mitigating every risk in every region would require unfeasibly high levels of investment, the cost of which could make electrification prohibitively expensive. In fact, system planners already predict an immense overbuild of storage and renewable resources to serve infrequent periods of high load and low renewable output<sup>14,15</sup>. At minimum, this dynamic encourages the exploration of grid alternatives for climate risk reduction in the face of uncertainty.

Transmission lines are one option that reduces reliability risk without additional generation investment. Assuming capacity shortfalls will not occur in two different regions at the same time, transmission lines effectively reduce risk through portfolio diversification—that is, by diversifying supply and demand exposure so that a single region is not solely exposed to risk. This approach could prove invaluable in a system characterized by high levels of climate uncertainty<sup>16</sup>. But political and logistical challenges often stall transmission expansion efforts, especially at the interregional level<sup>16</sup>. Further, research suggests that only 5% of operating hours contributes to 50% of a new transmission line's value, with high-value links between regions varying dramatically by year and weather conditions<sup>17</sup>. These challenges motivate the investigation of alternative means to move power between regions during infrequent resource shortfalls while avoiding the cost, locational rigidity and implementation challenges of transmission investments.

Dramatic improvements in battery technology<sup>18</sup> and costs<sup>19</sup> have created new opportunities in the electricity sector and cross-sectoral mobile storage applications. Some such applications have been

explored—for example, discharging electricity stored in electric vehicles (vehicle to grid) or using the road network to transport electricity in large batteries<sup>20–22</sup>. However, weight-carrying capacity limits constrain their application to regional-scale price arbitrage, operational flexibility and distribution system resilience<sup>23,24</sup>. Rail transportation, in contrast, has tremendous weight capacity to deliver large battery assemblies. A single train can carry 1 gigawatt-hour (GWh) of battery storage<sup>25</sup>, roughly equivalent to the carrying capacity of 1,000 semi-trucks<sup>26</sup>, and large-scale mobile containerized battery pilots are already underway for freight propulsion<sup>27,28</sup>. Covering 220,000 km, the US rail network is the largest in the world<sup>29</sup>, having both rights of way and property in some of the most population-dense and transmission-congested regions. A variety of studies have incorporated mobile battery storage on rail into daily power systems operational models<sup>22,30–38</sup>. These studies have found benefits including lower renewable curtailment<sup>33,34,37,38</sup>, increased operational flexibility<sup>22,33,35</sup>, transmission congestion relief<sup>30,31,33–36</sup> and peak load shaving<sup>30</sup>. However, they do not address benefits from avoided investment in redundant, stationary assets to serve infrequent periods of resource inadequacy. Further, these studies focus on theoretical representations of freight networks and assume—unrealistically—perfect scheduling coordination between the rail and power sector. Though this previous work serves as a theoretical basis for the benefits of mobile energy storage (MES), notable gaps remain, both in assessing its feasibility considering real-world freight scheduling constraints and evaluating the potential for rail-based MES to address low-frequency, high-impact reliability challenges at the national scale.

In this Article, we estimate the ability of rail-based mobile energy storage (RMES)—mobile containerized batteries, transported by rail among US power sector regions—to aid the grid in withstanding and recovering from high-impact, low-frequency events. Due to the



**Fig. 2 | Coincidence of historic high-value transmission arbitrage events.** **a**, The correlation coefficient between LMPs in each operating region with darker colours displaying higher correlations for the day-ahead (DAH) and real-time (RTH) markets<sup>43</sup>. Regions that are geographically separated or on different a.c. interconnectors have low price correlation (<0.5), while those that are geographically near one another have stronger correlation. **b**, Comparison of the estimated value of transmission lines using DAH and RTH prices<sup>43</sup>. Between

17% (DAH) and 25% (RTH) of total transmission line value is concentrated in 1% of hours. **c**, The percent of total bidirectional transmission value between nodes across regions that is in the same direction (that is, power always moving from Region 1 to Region 2). Over a ten-year period, on average, between 40% (unidirectional for a month) and 85% (unidirectional for a day) of total transmission value can be captured by sending power in only a single direction during the highest-valued hours.

predictability and non-coincident nature of high-impact events, we find that electricity jurisdictions could leverage this technology with minimal disruption to freight operations. As with stationary generators, RMES reduces risk by providing enough physical capacity in each operating region during tight supply conditions—but reduces total investment requirements. As with transmission lines, RMES reduces risk by diversifying a region's access to generating capacity—but utilizes existing infrastructure to avoid the financial and logistical expense of transmission expansion. Additionally, RMES can provide redundancy along existing transmission paths, which is valuable for reducing failures in critical infrastructure<sup>7,39</sup>.

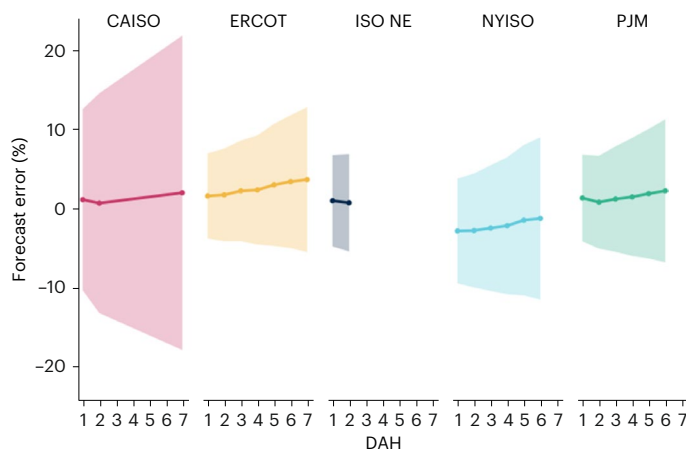
## Feasibility of RMES

To understand the feasibility of RMES in the freight sector, it is essential to assess whether RMES shipments among grid operating regions (referred to as independent system operators, or ISOs) would disrupt freight operations. We assess the temporal and spatial nature of freight operations using Waybill rail shipment reporting data<sup>40</sup>. Figure 1a shows that daily, most ISOs have between one and 50 train shipments travelling to them from each other state. Figure 1b displays the calculated travel time to move between each state and the ISO. Combining a 1–2-day scheduling time with industry-reported travel speeds and

shipment distances, we estimate it takes 1–6 days to move a battery between most ISOs, suggesting RMES could move between major power markets within a week without disrupting freight operations.

For RMES to be feasible in the power sector, three conditions must be met. First, as with transmission lines, high-impact, low-frequency grid stressors must occur at non-coincident times between operating regions. This pattern enables the same resource to be shared across both regions, rather than requiring each region to retain its own capacity. Unlike transmission lines, RMES cannot move power instantaneously but rather would take 1–6 days to arrive from another region. A second condition therefore is that grid stressors must be separated by enough time to move RMES resources between regions. Third, these events must be predictable, with sufficient lead time to schedule and execute RMES shipments.

To understand the coincidence of high-impact grid events, we examine the correlation of locational marginal prices (LMPs) between each operating region—California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), ISO New England (ISO NE), Midcontinent ISO (MISO), New York ISO (NYISO), Pennsylvania-New Jersey-Maryland Interconnection (PJM), and Southwest Power Pool (SPP). Using LMPs from 2010 to 2021, we calculate correlation coefficients of 0.3–0.7 between most regions (Fig. 2a)<sup>41</sup>. Geographically separated regions



**Fig. 3 | Mean forecast error in the top 10% of load hours, 2010–2020.** For all regions, the mean forecast error for 1–7 days ahead is below 5%, represented by the solid lines in each operating region. The shaded intervals around the solid lines represent one standard deviation from the mean forecast error. For regions except CAISO, the standard deviation of forecast error is approximately 5–10%, depending on region and number of days ahead, represented by the larger polygons in each market. CAISO has a larger standard deviation, perhaps owing to its high penetration of behind-the-meter renewable generation; its upper bound of forecast error is about 20%, one week in advance.

(for example, MISO and NYISO) and regions on different alternating current (a.c.) interconnects (for example, ERCOT and CAISO) have weaker price correlation, while those near one another (for example, ISO New England and NYISO) have much stronger correlation. This tendency suggests non-coincidence of high-priced events across regions.

As the value of transmission lines depends on price separation between regions (that is, limited supply in one region and excess supply in another), we use transmission valuation methods to assess the spatial coincidence of major grid stressors<sup>17</sup>. Using LMPs from 2010 to 2021, we calculate the value of a transmission line between each unique combination of two price nodes, both between different ISOs and within a single ISO. We find that 17–25% of the value of transmission connections is concentrated in 1% of the total hours it could be used (Fig. 2b), confirming there is considerable value in moving power between regions during the lowest-frequency, highest-impact events.

To understand the potential for specifically RMES to serve high-impact grid events, we focus on the top 1% highest-valued hours for each simulated transmission connection, assuming these are the hours where supply is most available in some regions while tightest in others. As trains cannot move power instantaneously between regions (and thus cannot arbitrage hourly price fluctuations like traditional transmission lines), we examine bidirectional arbitrage opportunities (for example, a traditional transmission line) in the day, week and month surrounding a high-value arbitrage event and compare that to the value of moving power in only one direction (for example, RMES) during those periods. As illustrated in Fig. 2c, roughly 85% of bidirectional arbitrage can be captured by unidirectional arbitrage on the day surrounding a high-impact event. This value drops to 40% and 70% for the month and week surrounding the event, respectively. This relationship suggests that most major events occurring in different regions are separated by at least a week. Thus, RMES could move among regions for days, weeks or months at a time and serve most low-frequency, high-impact events.

Even if such events are separated by ample time, they must also be reasonably predictable for RMES to be valuable. We examine the predictability of three types of historical event that have required excess generation capacity: extreme weather emergencies, major price spikes caused by supply–demand imbalances and annual peak-demand events.

Emergency events can sometimes be predicted several days in advance. Two recent emergencies, the 2020 California blackout and 2021 Texas winter storm, had three and eight days of notice, respectively<sup>20,42</sup>—well over the amount of time necessary for RMES scheduling and shipment. Seasonal and annual tight supply conditions can also be anticipated days or weeks in advance. To assess the feasibility of RMES to serve these periods, we estimate event predictability in two ways: (1) using day-ahead market prices as a proxy for tight supply predictability within one day of the event and (2) using gross load (that is, total electricity demand before netting out renewable generation) forecasts within 2–7 days of the event.

Annual day-ahead price spikes align with real-time price spikes over 90% of the time, suggesting high-impact events can be predicted with near certainty one day before they occur<sup>41</sup>. Thus RMES located within one day of a load centre could feasibly serve high-impact events using the day-ahead market as a commitment signal.

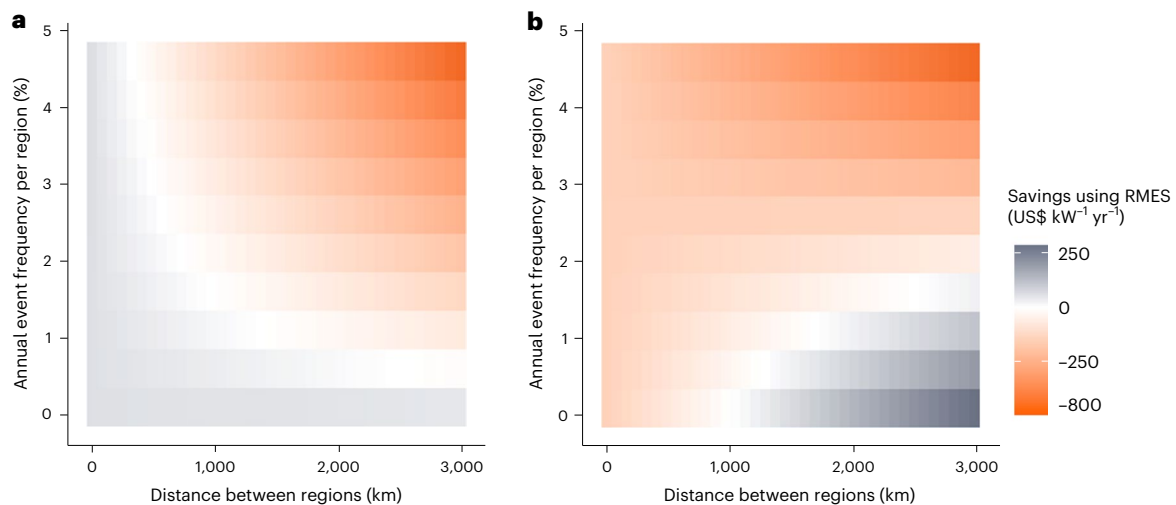
To assess the predictability of events 2–7 days away, we rely on gross load forecasts. Using data from 2010 to 2020<sup>43</sup>, we calculate the difference between predicted and actual loads for the top 10% of load hours of the year. On average, forecast load is within 5% of actual load (Fig. 3). The relatively low forecast error across regions suggests that RMES could effectively be summoned across regions to serve high-impact events. That actual forecasting techniques are much more accurate than gross load forecasts should lend further confidence in RMES.

### A cost-effective reliability solution for infrequent events

To assess the cost-effectiveness of RMES, we compare it to two strategies for maintaining reliability during low-frequency, high-impact events: (1) investing in stationary generating capacity in each region and (2) investing in transmission between regions. Strategy (1) assumes that two regions facing risk of high-impact events invest separately in stationary capacity to mitigate their risk. An example of such an event might include a period of extreme heat, as California experienced in September 2020, when demand was higher than predicted and the planning reserve margin was too low<sup>20</sup>. For the sake of simplicity, we assume battery storage as the stationary capacity resource of choice. Strategy (2) assumes that instead of investing separately in stationary capacity, the two operating regions invest in a new transmission line connecting them. Because this strategy diversifies supply, both technologically and geographically, it is already a strategy employed to mitigate the risk of renewable drought (that is, extended periods of weather-related low renewable energy output)<sup>44</sup>.

Figures 4 and 5 illustrate the potential cost savings from leveraging RMES to maintain grid reliability as compared to the two strategies above. Compared to stationary battery storage (Strategy (1)), RMES is more economical for low-frequency events when the distance between regions is small (Fig. 4a). For example, if RMES travels a total of 400 km between regions, it is more economical than stationary batteries when the resources are called upon <2% per region annually. RMES is also more economical than transmission investment (Strategy (2)) for low-frequency events, but, unlike stationary capacity, the cost-effectiveness of RMES grows compared to transmission as the distance between regions increases (Fig. 4b).

Figure 5 compares the fixed and variable costs of RMES, duplicative stationary capacity and new transmission lines based on (1) frequency of events and (2) distance travelled between regions. As event frequency increases (that is, the resource is called upon more often), the fixed costs of stationary capacity and transmission lines remain constant, while the variable costs of RMES increase considerably. Thus, RMES is more economical than these alternatives when its fixed cost savings exceed its high variable costs. As distance between regions increases, RMES decreases in value compared to stationary capacity investments but increases in value compared



**Fig. 4 | Savings from using RMES compared to stationary capacity and transmission investments. a**, The cost savings from using RMES instead of stationary capacity resources (that is, battery energy storage). **b**, The cost savings from using RMES instead of transmission lines. Darker red indicates higher costs for RMES relative to stationary storage or transmission lines, while darker grey represents higher savings. As AEF increases, RMES becomes less economic compared to both stationary storage and transmission lines. As distance travelled between regions increases, RMES becomes less economic

compared to stationary storage. At low AEFs, RMES becomes more economic than transmission lines as distance increases because the per-km increase in RMES shipment cost is lower than the per-km increase in transmission capital expenditure. This relationship is reversed as event frequency increases. Generally, RMES is economic as a replacement for stationary capacity at all distances when AEF is under 1% and economic as a replacement for transmission when distances between regions exceed 1,500 km.

to transmission lines, because transmission line capital costs increase more rapidly with distance than do the variable costs of moving batteries via rail (Fig. 5b).

What does this imply for the beneficial application of RMES? When operating regions are closer together (for example, within 400 km), RMES may be more cost-effective than stationary capacity investments for addressing high-impact, low-frequency events, especially if their occurrence is at or below 1% annually in each region. For very rare events (0.1% annual event frequency (AEF)), RMES is valuable compared to stationary batteries regardless of the distance between regions. When operating regions are farther apart, RMES may be more cost-effective than new transmission to address low-frequency, high-impact events. This is particularly valuable for mitigating the risk of renewable droughts, as RMES would allow regions experiencing low renewable output to access regions with more favourable weather conditions.

### Increasing grid resilience in the face of uncertainty

The unpredictability and immense impact of extreme events challenges system planners who are struggling to prepare as these events become more frequent and severe<sup>10,45,46</sup>. Though the cost of power interruptions during these events is estimated to range from US\$360 MWh<sup>-1</sup> to \$300,000 MWh<sup>-1</sup>, their variability and spatial and temporal uncertainty pose financial and logistical challenges to typical grid reliability and resilience approaches<sup>47–50</sup>. Due to these challenges that extreme events pose, the Federal Energy Regulatory Commission (FERC) does not yet have effective strategies for addressing them, instead proposing a ‘case-by-case’ approach<sup>45</sup>.

RMES can address diverse and uncertain supply shortfall risks across regions without the economic toll of case-by-case stationary assets or dedicated transmission investments. Additionally, RMES offers an important attribute for grid resilience: redundancy. The power sector has long valued redundancy by enforcing  $N - k$  contingency standards (that is, having enough operational redundancy such that if  $k$  capacity or transmission elements are unavailable, the grid can still operate)<sup>51</sup>. RMES provides this redundancy from both the capacity

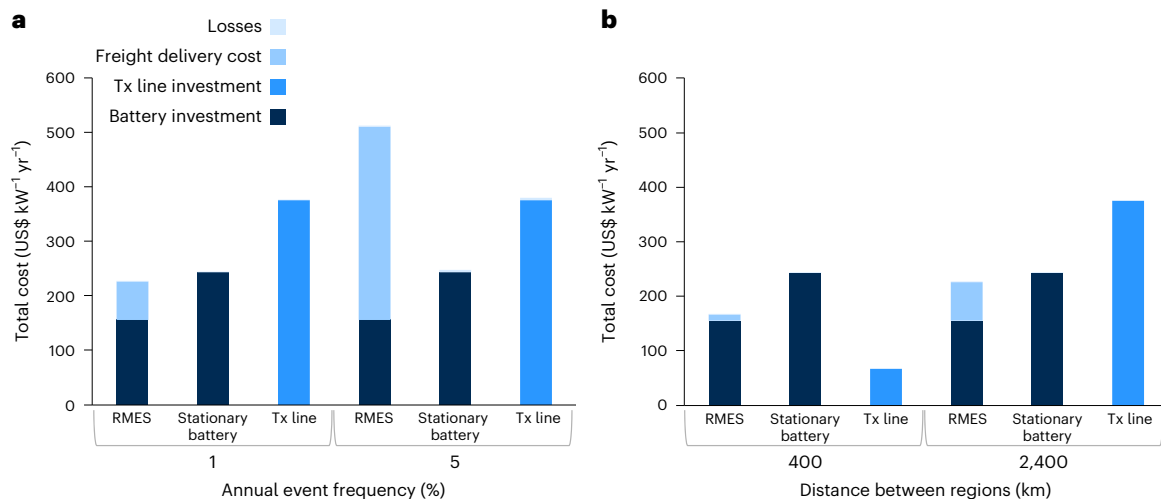
and transmission perspective. Nine US states have established energy storage targets, collectively totalling 16 GW by 2035<sup>52</sup>. The spatial flexibility of storage assets would make available large amounts of capacity redundancy if generators were damaged or offline following an extreme event. Further, the rail network would serve as a different form of transmission redundancy, even between regions with existing lines. While the rail network contends with its own resiliency challenges in the face of extreme temperatures, the combination of redundant cross-country routes and the industry’s multi-billion dollar annual investments in winter-proofing activities reduce risk for rail transport even during extreme events.

### Applying RMES to New York’s grid operating region

Here we demonstrate the value of RMES to New York state. We chose New York for two reasons. First, resources built to ensure resource adequacy in New York are highly underutilized. For example, between 2011 and 2020, approximately 1.1 GW, or one-third, of New York City’s peaker plants had an average capacity factor of 1% or less<sup>53</sup>. Second, substantial transmission constraints cause price separation between upstate clean energy generation and downstate load centres (Fig. 6a)<sup>14,54</sup>. These factors suggest that RMES could replace a portion of the state’s investment in underutilized and duplicative resources while circumventing transmission constraints.

On average, it takes between 1 and 11 hours to move freight by rail between regions of New York, with approximately 1–3 freight trains moving between regions of the state each day<sup>40</sup>. Inclusive of scheduling time, RMES would need only 1–2 days of lead time to be summoned to a region for a high-impact event, well within the predictability window we observe in current markets.

As with the nationwide estimate, we consider the potential benefits of RMES to New York by analysing LMP data and calculating the value of a new or upgraded transmission connection between zones to relieve congestion<sup>41</sup>. We find that approximately 14% (DAH) to 26% (RTH) of total potential transmission arbitrage value is concentrated in the top 1% of price hours. We also find considerable value in



**Fig. 5 | Costs of RMES compared to stationary capacity and transmission investments. a,** How AEF affects costs for each resource when regions are separated by 2,400 km. **b,** How distance affects costs for each resource when AEF is 1% in each region. Stationary capacity (that is, battery energy storage) has high up-front fixed costs (battery costs; siting, developer and interconnection costs; and fixed operations and maintenance costs) due to the duplicative battery investment. Relatively low variable costs keep the total cost of the stationary

battery investment consistent as AEF and distance increases. A transmission line (Tx line) also has high fixed costs. These costs increase with distance between power sector regions, but relatively low variable costs keep the total cost consistent as AEF increases. RMES has the lowest up-front fixed costs, but rail network transport costs increase considerably with AEF (a) and distance between power sector regions (b).

unidirectional arbitrage (that is, RMES) during those periods. Whereas nationwide, approximately 40–85% of the bidirectional transmission value remains if storage is moved only one way during a day, week or month period surrounding a high-impact event, between 85% (month) and 95% (day) of the total value remains in New York. This suggests that the additional transmission capability provided by RMES during these small numbers of hours could still offer incredible value, even though it cannot arbitrage bidirectionally or instantaneously like a traditional transmission line.

New York has established a 100% renewable target by 2040<sup>55</sup>. To maintain reliability, it could overbuild nearly 100 GW of renewables plus storage and curtail more than 220 TWh of renewable generation every year<sup>15</sup>—equivalent to 1.5 times statewide energy demand in 2020<sup>56</sup>. A major driver of this overinvestment is the risk of a downstate wind drought. New York's 2019 Climate Leadership and Community Protection Act<sup>55</sup> calls for installing 9 GW of offshore wind by 2035. Though this investment will provide large amounts of carbon-free energy to New York's largest load centre, existing transmission constraints leave the area vulnerable to supply shortfalls.

New York is considering more than US\$3 billion in transmission investments to address some of these concerns, including the Champlain Hudson Power Express, a high-voltage direct current (HVDC) transmission line running from downstate New York to Quebec<sup>57,58</sup>. RMES could be a compelling and cheaper alternative to some portion of this investment. Not only would it increase access to hydropower in upstate New York and Canada, but it would also unlock access to renewable resources, such as Midwest wind and Southwest solar, that are only a few days away by rail. Further, by diversifying import paths into key load centres and providing backup power during emergencies, RMES could improve grid resilience, a key priority for NYISO<sup>10,14</sup>.

## Regulatory and interconnection considerations

If policy and market barriers are addressed, RMES could technically be deployed in the near future and earn revenues in one of three ways: as an energy-only resource, a capacity resource or as a transmission resource.

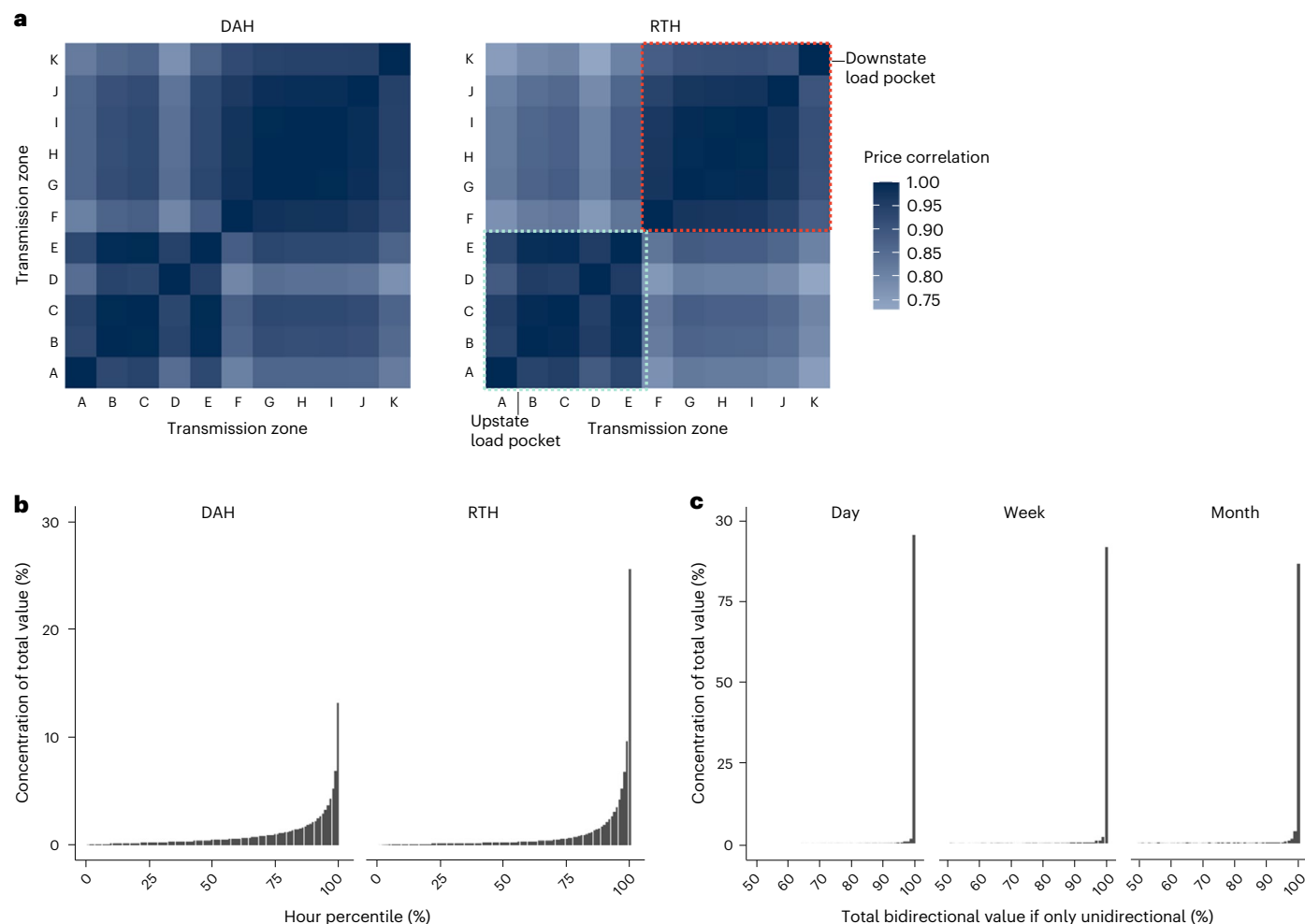
Serving as an energy-only resource would lend the most flexibility, as resources are not typically required to bid into all hours of the year (an important feature for assets that could be located outside markets

they serve). This approach may not be viable in markets beyond ERCOT because energy market prices are typically insufficient to recover investment and interconnection costs in just a few hours per year. In some regions (for example, PJM and NYISO), investments that serve primarily to ensure resource adequacy earn most of their revenue through payments as a capacity resource. This approach allows resources to be compensated for their reliability value regardless of how much electricity they provide. Market rules currently constrain this pathway; for example, capacity resources must bid into day-ahead markets for all hours of the year, except during outages<sup>59</sup>. Even if RMES bid in at a very high price, it may still clear the market when it is not there to perform, thereby incurring financial penalties and threatening reliability. One solution to minimize risk could be to leave a portion of RMES capacity permanently at a point of interconnection, with the rest of the storage providing additional duration when present. A third option would be to serve as a *transmission resource*. Though RMES could effectively act as a peak-serving transmission line, FERC does not yet recognize it as such<sup>60</sup>.

Interconnection issues also challenge RMES deployment, as sizable and sometimes cost-prohibitive upgrades may be needed to discharge such large batteries. Finding viable business models for interconnecting these resources is therefore imperative. Railroads operate in every major US city, often with railyards in urban centres<sup>61</sup>. Using existing MW-scale interconnections, such as the one at New York's Long Island City railyard, is one solution. Another could be to utilize the interconnection rights of retiring or decommissioned power plants near rail lines. In general, capitalizing on existing land and interconnection rights could dramatically reduce costs compared to siting RMES in new locations. Future research could assess optimal siting to maximize grid reliability benefits while minimizing interconnection costs.

## Discussion

Nations will become increasingly reliant on electricity grids as they pursue decarbonization, making reliability a top policy priority. We show that sharing flexible, multi-purpose RMES assets across regions and sectors is a viable, cost-effective strategy for enabling a reliable and resilient clean energy future. We find that moving RMES across short distances (<400 km) could be more economic than stationary capacity



**Fig. 6 | Estimated capacity-sharing potential in the New York ISO. a**, The price relationship between transmission zones in NYISO. There is strong correlation among upstate zones (A–E) and among downstate zones (G–K) but little between upstate and downstate, which aligns with NYISO’s reported upstate–downstate transmission constraints during high-demand hours. **b**, Between 16% (DAH) and

26% (RTH) of all potential transmission arbitrage value is concentrated in the top 1% of hours. **c**, The remaining value that a transmission line would have in the top 1% of hours if it were only to provide unidirectional arbitrage in the day, week and month surrounding a high-impact event. Between 2010 and 2021, approximately 85–95% of the value would remain.

investments for low-frequency events (called upon <2% annually per region). For extremely rare events (0.1% annually), RMES is beneficial compared to stationary capacity at all distances. Whereas RMES is not economic compared to transmission at short distances, it becomes cost-effective for low-frequency events as distance between regions grows. Though we do not quantify this in our study, RMES could also be more advantageous than transmission in the near term due to difficulties securing transmission rights of way.

Though RMES does not provide the same dynamic reserve capability as fast-response stationary assets (for example, to address sudden frequency drops), it can feasibly address high-impact grid events that are predictable multiple days in advance. Our study conservatively focuses on the value of sharing RMES between two regions. However, a larger benefit of RMES stems from its ability to replace stationary investments in additional regions as well. Replacing multiple stationary storage or transmission investments would indeed be possible given the non-coincidence of transmission needs (Supplementary Fig. 1). In the case of a stationary storage, the cost of the battery contributes approximately 72% to the total fixed costs of the investment (US\$89 per kW-year (kW<sub>y</sub>) of the US\$122 kW<sub>y</sub><sup>-1</sup>). For every location where RMES replaces stationary storage, the system saves the full cost of the battery. This exceeds the upper bounds of total ancillary service

revenues that batteries have recently been earning (–US\$70 kW<sub>y</sub><sup>-1</sup>)<sup>62</sup>. Similarly, replacing or supplementing transmission investments with RMES would save the full cost of an additional transmission line investment (for example, –US\$100 kW<sub>y</sub><sup>-1</sup> for an 805 km line).

No technical barriers prevent RMES from being utilized in the power sector. In fact, analogous business models exist for electric school buses in the United States<sup>63</sup>. Rather, barriers to RMES deployment relate to interconnection logistics and costs and electricity regulation. While strategic siting could reduce interconnection hurdles, further work is needed to assess market-specific interconnection opportunities and simulate feasibility based on freight operations data. Revising state and federal regulatory frameworks would be needed to include RMES assets in reliability markets and planning processes.

This paper presents a high-level overview of the benefits of RMES in the United States. However, the study is limited in its assessment of RMES’s impact on power-system planning and operational decisions. The study’s reliance on historical gross load data does not fully address the predictability of high-impact events, which will increasingly be driven by renewable output and extreme weather conditions. The study also does not assess the ways in which high-impact event coincidence will change in a rapidly decarbonizing energy landscape. With access to more advanced forecasting trends, future research could assess more

rigorously the limitations of forecasting high-impact events days to weeks out. Detailed modelling of decarbonized grid and future climate conditions will be needed to assess the future coincidence of high-impact events. Further, this study considers only the cost savings associated with RMES and does not model the operational benefits. Future work should integrate RMES into system planning and dispatch models to better understand this value compared to stationary assets or transmission lines. This could be assessed both regionally and nationally, in the United States and in other countries with extensive rail networks.

The potential to share RMES is not limited to only the power sector. Many nations with extensive rail networks rely on diesel-electric trains (for example, the United States, Canada, Russia and China), necessitating cost-effective, scalable zero-emission technologies in the near term<sup>64</sup>. Standardizing RMES resources and providing energy as a service to the freight industry could generate tremendous economic gains across sectors. The freight rail industry is already adopting battery-electric locomotives<sup>65,66</sup>. Ongoing container ships can be powered cost-effectively by containerized battery systems that charge every 1,500 km<sup>67</sup>. This could create a meaningful business opportunity and unlock an estimated 220 GWh of MES for power sector use during extreme events<sup>25</sup>. Certain locations may be well positioned for a preliminary demonstration of this concept. California's Low Carbon Fuel Standard (LCFS), for example, provides an incentive for producing electricity as a diesel fuel substitute in the transportation sector<sup>68</sup>. For RMES owners, LCFS credits could offset a large portion of the up-front investment costs in batteries and/or charging infrastructure. This policy would dramatically increase the profitability of cross-sectoral RMES sharing and could accelerate decarbonization of the rail sector.

## Methods

### Freight rail location and travel time

We examine the temporal and geospatial nature of freight shipments using 2019 Waybill sample data<sup>40</sup>. Utilizing origin–destination pairs and shipping volumes, we estimate the average number of trains departing daily from each state in the United States and destined for each ISO. Ignoring scheduling time and station stops, trains travel approximately 65–80 km hr<sup>-1</sup> for 23–24 hr d<sup>-1</sup> (ref. 69). Thus, trains carrying RMES could travel 1,480–1,930 km d<sup>-1</sup>. We multiply the slower of these speeds with the average reported distance between each shipment location to estimate the maximum time it would take to move a train from one freight region to another. We assume that batteries are added onto another freight shipment that is scheduled to go out, which adds up to two days of railyard scheduling time to the calculation<sup>70</sup>. This time could be avoided if batteries are transported as a unit train, that is, from one origin to a specific destination with enough batteries to merit a dedicated train (for example, 60 or more).

### Assessing high-impact event coincidence

Though not a perfect representation of tight supply conditions, high energy prices often indicate periods of grid stress. To understand the temporal nature of high-impact events, we rely on empirical transmission line valuation methodology because, like transmission lines, the value of RMES lies in there being non-coincidence of tight supply conditions<sup>17</sup>. We first subset all LMP nodes in the United States to those representative of pricing zones in each major ISO. Using historical day-ahead and real-time LMPs from 2010 to 2021<sup>41</sup>, we estimate the value of a transmission line between each unique pair of price nodes by comparing hourly price differentials. To estimate the value in only the highest-impact event periods, we limit our focus to the top 1% of the simulated transmission line's valued operational hours. Because RMES, unlike transmission lines, cannot flow power instantaneously, we calculate the remaining value in a transmission connection if the power were only able to flow unidirectionally for a day, week or month surrounding the event and compare that to the total value of bidirectional flow potential during those periods.

### Assessing high-impact event predictability

Our methods for assessing high-impact event predictability vary based on number of days in the forecast period. For events occurring within one day of the forecast period, we use day-ahead market clearing prices<sup>41</sup> as a proxy for load forecast. For events occurring 2–7 days after the forecast period, we assess event predictability using gross load forecast data from 2010 to 2020<sup>71</sup>. Due to the strong correlation between load and temperature<sup>72</sup> and historic connection between high-impact grid events with extreme temperatures, we feel confident using gross load forecast accuracy as a proxy for high-impact event predictability. Load forecasts vary by ISO, with ISOs forecasting from one day ahead (for example, MISO) to seven days ahead (for example, ERCOT). We compute forecast error as the percentage difference between the forecast load and the realized load each day.

As load forecasts predict only gross load, or the total demand on the system without netting out renewable generation, we compare realized gross load with day-ahead and real-time prices to understand the relationship of peak load and peak pricing events. We find some variation between the top 1% gross load and top 1% price events, suggesting gross load forecasts may not always predict times when supply is tightest (that is, peak prices). Net load (that is, load minus renewable generation) and weather forecast data may be a better way to forecast tight supply conditions. Though we did not have access to net load forecast data for this study, utility documentation suggests these practices are incorporated into current ISO and utility load forecasting<sup>73,74</sup>.

### Fixed and variable costs of stationary capacity, RMES and transmission lines

Supplementary Table 1 summarizes the inputs to the model comparing the all-in costs of stationary capacity, RMES and transmission lines. For stationary capacity and RMES, we assume at least one battery investment plus the cost of two points of interconnection. Equation (1) provides the estimated fixed cost for a stationary battery resource, where  $B_d$  is the duration of the storage;  $B_C$  is the capital cost of the battery;  $B_{SDI}$  is the siting, interconnection and developer costs; and  $B_{FOM}$  is the fixed operations and maintenance costs<sup>75</sup>. The total fixed costs for stationary battery storage are multiplied by two to account for duplicative investments in two separate regions. Equation (2) provides the estimated fixed costs for RMES, which includes two points of interconnection ( $B_{SDI}$ ) for the one battery that is used. We assume a four-hour storage duration; a 'moderate' cost decline projection for battery costs (provided in Supplementary Table 2); and a cost decline projection year of 2025. Supplementary Table 3 lists battery investment cost components.

$$\text{Fixed cost}_{2 \times \text{stationary generation}} = 2(B_d \times B_C + B_{SDI} + B_{FOM}) \quad (1)$$

$$\text{Fixed cost}_{\text{RMES}} = B_d \times B_C + 2B_{SDI} + B_{FOM} \quad (2)$$

We calculate fixed costs of a transmission line as equal to cost of the transmission line investment plus two substations. We assume a 345 kV single-circuit transmission line for this analysis, though the tool we use to calculate transmission costs can calculate costs for other voltages and types of line as well. We use US\$8.27 (kW km)<sup>-1</sup>, the cost for a 345 kV a.c. line, inclusive of land acquisition costs<sup>76,77</sup>.

Variable costs differ by resource type. For stationary capacity, we assume the only variable costs are energy losses due to battery round-trip efficiency (RTE) (that is, total MWh loss multiplied by the average off-peak electricity price paid to charge the battery). For transmission lines, we calculate the variable costs as transmission line energy losses. For RMES, we calculate variable costs as battery RTE losses plus freight delivery costs (that is, the cost of moving RMES over the freight network). We calculate the value of all energy losses at the average off-peak electricity price of US\$30 MWh<sup>-1</sup> (assumptions provided in Supplementary Table 4). For losses due to battery



inefficiency, we assume an 85% RTE<sup>75</sup>. Transmission losses are assumed at 0.01% km<sup>-1</sup> (ref. 76).

Equation (3) describes the freight delivery costs of RMES, where  $U_p$  is the AEF per region,  $n$  is the number of regions utilizing the RMES resource (we assume 2 for this analysis),  $R_f$  is the freight delivery rate and  $d$  is distance between regions. We estimate the freight delivery rate at US\$0.03 (t km)<sup>-1</sup> (ref. 78). Assuming a 9 MWh per-battery-plus-inverter weight of 89 t<sup>25</sup>,  $R_f$  is US\$3 km<sup>-1</sup>. We estimate the total number of annual deliveries as the total number of hours of the year, multiplied by the per region AEF,  $U_p$  and the number of regions utilizing the resource,  $n$ . We divide this number by the storage duration  $B_d$ , assuming each four-hour battery is meant to arbitrage four hours of event duration.

$$\text{Freight delivery costs} = n \times \frac{U_p \times 8,760}{B_d} (R_f \times d) \quad (3)$$

## Data availability

The electricity system data utilized in this study can be accessed either with a license to Velocity Suite or via individual aggregation from each ISO's public data repository. Waybill sample data for rail commodity flows are not public but can be applied for by any individual with a federal government affiliation. Source data used to generate the figures in this paper are included in the source data section. Source data are provided with this paper.

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## Author contributions

J.W.M. conducted the analysis and wrote the paper. N.D.P. wrote sections of the paper and provided guidance on and data for the analysis. A.A.P. conceived the idea and secured funding for the project.

## Competing interests

The authors declare no competing interest.

## Additional information

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