Reimagining the Electricity Sector in Island Nations with Virtual Power Plants

Insights from the US Virgin Islands and guidance for implementation in the Caribbean and beyond

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About RMI

RMI is an independent nonprofit, founded in 1982 as Rocky Mountain Institute, that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing.

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Executive Summary

Caribbean countries are universally renowned for their turquoise waters, pristine environment, and vibrant local culture. However, a common plight lurks in the background of most islands: a deep dependence on expensive, polluting fossil fuels for electricity generation. This reliance contributes to the unique vulnerability of island nations to volatile global fuel prices that can cripple local economies by driving up electricity prices.

Furthermore, the aging and fragile grid infrastructure in many Caribbean countries leads to numerous electricity outages each year. Most critically, the increasing threat of climate change and its associated extreme weather events are omnipresent across the region. Hurricanes pose a consistent risk to the infrastructure and livelihoods in island nations, as they are capable of devastating entire power systems and leaving communities without power for months.

Yet, amid these challenges, a powerful solution is emerging in the form of distributed virtual power plants (VPPs). These innovative systems provide an opportunity to fundamentally transform Caribbean energy systems, empowering communities to take control of their energy future by shifting the power sector from a centralized system to a distributed system. This report delves into the transformative potential of VPPs in this unique context, zooming in on a detailed case study from the US Virgin Islands (USVI) to illustrate the tangible benefits and practical strategies for successful VPP implementation in the broader Caribbean context.

The *VPP Background* section provides a foundational understanding of a distributed VPP, outlining its key components and functionalities. *USVI VPP Study* details an in-depth case study of a distributed VPP analysis in USVI, examining the impact of a VPP program on grid stability, cost savings, and energy resilience, and offering concrete evidence of the value of distributed VPPs. Finally, *Expanding VPPs across the Caribbean Region* broadens the focus to the wider Caribbean region, extrapolating the insights and lessons learned from the USVI VPP case study to other island nations. Specifically, the applicability and replicability of distributed VPP programs in island nations is considered, given the unique characteristics of electricity systems across countries. The section gives tailored recommendations for successful VPP implementation across island nations, and more broadly in the Global South.

This report spotlights how VPPs, by aggregating distributed energy resources like rooftop solar panels and battery energy storage systems (BESS), can unlock a future where Caribbean nations will have greater energy resilience, lower electricity costs, a more flexible power supply, and a reduced reliance on volatile fossil fuel prices. In parallel, VPPs can accelerate the transition to cleaner, renewable energy sources, reducing greenhouse gas emissions and contributing to the global fight against climate change. Join us as we uncover the potential that distributed VPPs offer to forge a new era of energy independence, resilience, and sustainability for island nations.

Virtual Power Plant (VPP) Background

In most countries, particularly island nations, the electricity system is powered by massive, centralized (often fossil fuel) power plants, delivering electricity to customers through an intricate transmission and distribution (T&D) system. Imagine if considerable portions of the electricity network were complemented by networks of smaller, cleaner energy sources installed across homes, businesses, and industrial facilities, and communicating with a central operating system.

This is the concept behind the virtual power plant (VPP), which is a network of interconnected, decentralized energy sources that can be actively managed and controlled as a single, unified entity by a VPP aggregator. Unlike traditional fossil fuel power plants that rely heavily on a large, centralized power grid infrastructure, VPPs leverage the collective power of smaller, decentralized assets such as:

- Renewable energy sources that could include solar panels, wind turbines, small-scale hydro plants, or even biofuel generators
- Energy storage systems such as battery energy storage systems (BESS), pumped hydro storage, and other energy storage technologies
- Flexible loads that encompass demand-side resources like smart thermostats, electric vehicle chargers, and industrial processes that can adjust their energy consumption based on grid needs

By aggregating these diverse distributed energy resources (DERs), VPPs can mirror the operational behavior of conventional power plants, providing a range of services to the grid. Most notably, they provide electricity to the grid when available and called upon. VPPs can also provide capacity support by managing peak demand to reduce consumption during periods of high electricity demand on the grid. Furthermore, they can provide critical ancillary services, such as frequency regulation and voltage support, helping ensure grid reliability and resilience. VPPs can take various forms, and many VPP programs have already been implemented in several regions across the world (see Exhibit 1).

Exhibit 1 Types of VPPs and real-life examples

	Utility and multicountry–level VPPs	Distributed-level VPPs	Demand-side management VPPs
Definition	Aggregate commercial and utility-scale renewable assets across wide geographical areas, sometimes spanning multiple countries. Participate in wholesale energy markets and facilitate renewable asset trading.	Aggregate localized DERs such as rooftop solar and residential/commercial batteries in a more localized geography. Rely on participant compensation schemes and utility partnerships.	Aggregate flexible loads rather than generation assets. Include smart thermostats, EV batteries, and adjustable industrial processes to provide grid services and demand response.
Examples	Germany's Next Kraftwerke connects 14,000+ assets across Europe (12,700 MW capacity, 7+ countries). Voltalis (France) aggregates more than 1.5 million assets across 8 countries via its demand-response management platform.	Vermont's Green Mountain Power aggregates home battery systems through its BYOD program. Similar implementations in islands include Hawaiian Electric's BYOD Tariff program and Puerto Rico's Sunrun and Sunnova VPPs, which provide support during emergency grid events.	Arizona Public Service's Cool Rewards program virtually controls 145 MW of load via smart thermostats. Portland General Electric in Oregon manages 52.9 MW in demand response programs across thermostats, EVs, and water heaters. In Michigan, DTE Energy's Smart Charge program optimizes EV charging during off-peak periods.

RMI Graphic. Source: Next Kraftwerke, **https://www.next-kraftwerke.com/vpp**; Green Mountain Power, **https://greenmountainpower.com/rebates-programs/home-energy-storage/bring-your-own-device/**; Sunrun Inc., **https://investors.sunrun.com/news-events/press-releases/detail/310/sunruns-poweron-puerto-rico-virtual-power-plant**; aps, **https://www.aps.com/en/About/Sustainability-and-Innovation/Technology-and-Innovation/Cool-Rewards**; and DTE, **https://www.dteenergy.com/content/dam/dteenergy/deg/website/residential/Service-Request/pev/plug-in-electric-vehicles-pev/SmartChargeBrochure.pdf**

For small island nations facing unique energy challenges — including limited land for large infrastructure, high dependence on imported fossil fuel, and vulnerability to climate disasters — distributed VPPs offer a particularly compelling solution. A successful distributed VPP incorporates many stakeholders and components, as diagrammed in Exhibit 2, to function effectively:

1. **Distributed energy resource (DER) assets and VPP participants:** These form the foundation of any distributed VPP. Participating households, businesses, or facilities with distributed solar or BESS allow their system to contribute a portion of their capacity to a VPP program. In island settings, where electricity grids suffer occasional reliability issues, VPPs can serve dual purposes: providing renewable energy generation and energy security for individual owners while also creating collective grid resilience in the VPP.

   DER assets such as solar photovoltaics (PVs) and BESS are actively controlled in the distributed VPP, available to a VPP aggregator that deploys the cumulative capacities or capabilities from hundreds or thousands of VPP assets to be dispatched for grid services. Participation in the VPP is typically incentivized through compensation offered to VPP participants that accounts for the energy value and grid stabilization benefits provided by VPP assets. The services provided by VPP assets are critically important in isolated island grids where frequency and voltage fluctuations are common challenges.

2. **Energy management system (EMS) and user interface:** Many DER assets are accompanied by devices that monitor generation and other key metrics, such as electricity consumption and battery charge status. These devices also provide intuitive interfaces that help DER owners understand the contribution of their assets to the grid or VPP program.

   Many successful VPPs emphasize user control, allowing participants to select the extent of the contribution from their DER assets to a VPP program, and the level of control an aggregator has over these assets, during a specific time or up to a specific limit. This builds social acceptance through flexibility and transparency in the process. In island communities, where energy literacy and community engagement are often high priorities, energy management systems that form part of the VPP serve as informative tools alongside their technical functions.

3. **Communication network:** A reliable and secure communication network for a VPP program is essential for real-time data exchange between the energy management system and participants, the aggregator, and the grid. This network enables the flow of information on key metrics such as electricity generation, consumption, battery charge status, and grid conditions. Ensuring the security of the data transmitted is crucial to protect against cyberattacks that could disrupt VPP operations or compromise user privacy. Resilient communication systems are therefore essential to a VPP, often combining multiple redundant channels such as cellular, mesh networks, and satellite backups.

4. **VPP aggregator and aggregator platform:** The VPP aggregator and its respective aggregator platform act as the central control system for the VPP. The aggregator platform collects data from individual energy management systems and users (via their user interfaces), analyzes grid conditions, and determines the optimal dispatch schedules (e.g., BESS charging and discharging times) for VPP assets to enable them to provide grid services. For example, BESS could be programmed to charge during periods of low electricity demand and discharge during periods of high demand or grid congestion.

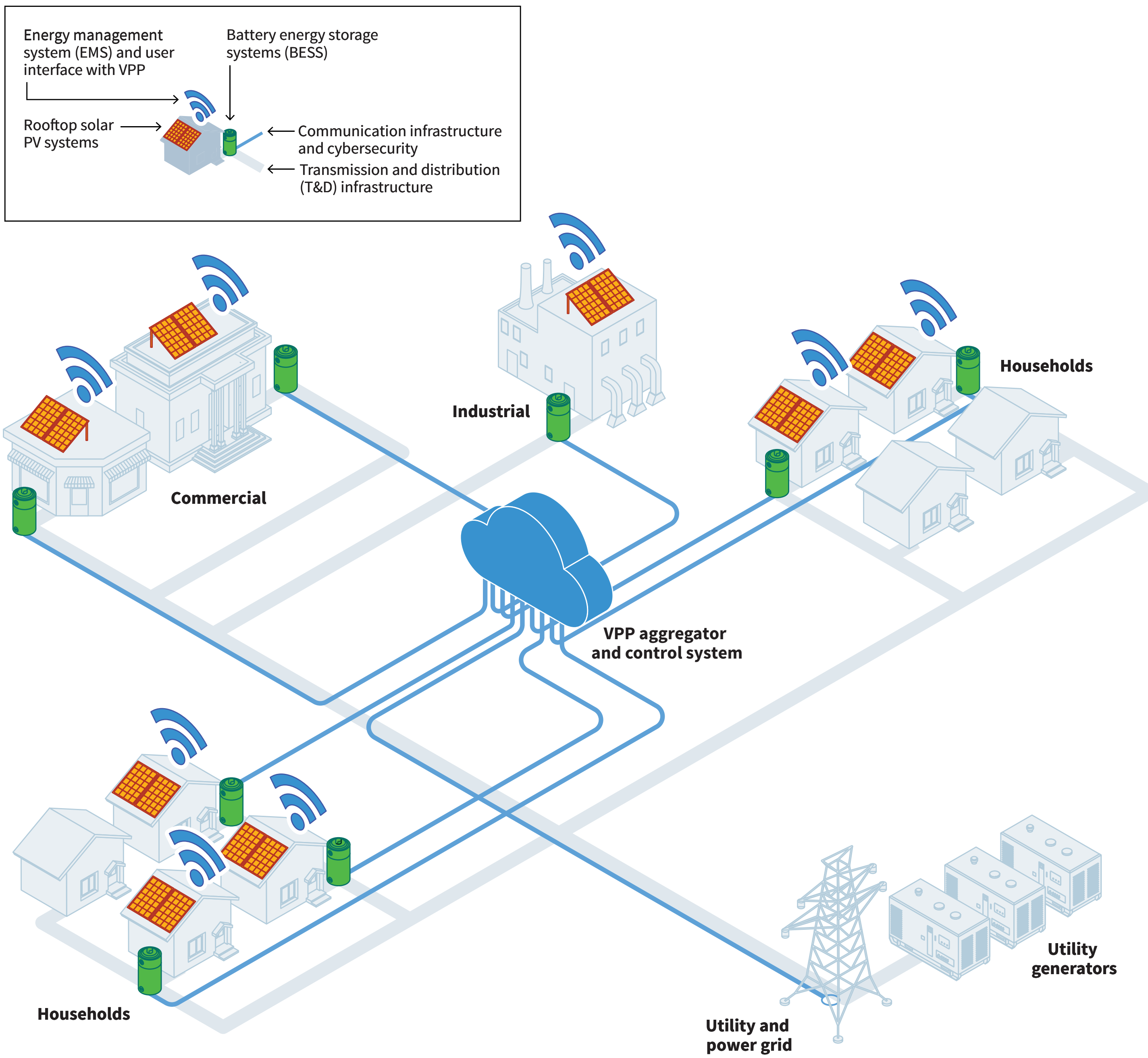
   Aggregators must excel at predictive capabilities, particularly regarding weather patterns and grid conditions that affect generation potential and grid stability needs. As such, artificial intelligence (AI) will play an increasingly pivotal role in VPP operations by enabling predictive analytics for renewable generation, optimizing real-time grid balancing, and enhancing decision-making processes across distributed assets. AI algorithms can forecast weather patterns affecting solar generation, anticipate demand fluctuations, and orchestrate the complex interplay among thousands of individual DERs to maximize grid stability and economic value.

   The VPP aggregator also plays a crucial role in grid integration and the interaction between the VPP assets and the grid. The aggregator platform communicates with the grid operator to receive signals on grid conditions, such as frequency deviations and voltage fluctuations. The VPP can then respond to these signals by enabling VPP assets to provide energy, capacity support, or ancillary services such as frequency regulation and voltage support. This coordination becomes especially valuable during extreme weather or grid outage events, when the VPP can help stabilize the grid during recovery operations and provide emergency power to critical infrastructure.

5. **Utilities and regulatory authorities:** Electric utilities must play an active and critical role in any VPP program. Utilities in small island nations face unique operational challenges, including fuel supply logistics for electricity generation, distribution system hosting capacity limits for DERs, and seasonal demand fluctuations in electricity demand. VPP integration therefore requires regulatory frameworks that recognize these constraints while incentivizing the deployment of DERs.

Successful VPP programs typically include significant utility involvement and cooperation, together with reasonable compensation mechanisms that reflect the value of the core services provided by the VPP (e.g., the avoided cost of fossil fuel), emergency response protocols that prioritize maintaining electricity supply for critical facilities during disasters, and community benefit requirements that ensure equitable participation across socioeconomic groups.

Exhibit 2 Visual representation of a distributed VPP with the various components identified



RMI Graphic.

In the Caribbean, distributed VPPs have transformative potential to address the region's unique energy challenges. Because they are heavily reliant on imported fossil fuels for electricity, many Caribbean countries have expensive electricity costs, averaging $0.34 per kilowatt-hour (kWh).[1] Caribbean electricity grids are affected by occasional grid instability and high vulnerability to extreme weather events, such as hurricanes. Driven by these challenges and coupled with the increasing economic viability of DERs, such as solar PV and BESS, electricity customers are already rapidly adopting distributed resources for cheaper, more reliable electricity.

This surge in DERs presents a timely and promising opportunity to integrate them into VPPs, strengthening energy security, enhancing grid resilience, and accelerating the transition to cleaner energy. By leveraging existing and future DERs, VPPs can significantly reduce dependence on expensive and polluting fuel imports, create a more robust and decentralized grid resilient to extreme weather events and other grid disruptions, and help reduce electricity-system costs. In the process, VPPs can stimulate local economies by generating jobs in renewable energy installation, maintenance, and technology sectors, and fostering economic activity through a more affordable, reliable, and sustainable electricity system.

To illustrate the potential benefits and implementation considerations for VPPs in an island setting, a case study of a VPP analysis for the US Virgin Islands (USVI) is examined in the next section. In 2024, RMI collaborated with the Virgin Islands Energy Office (VIEO) to conduct an analysis assessing the potential of harnessing DERs across the US territory into a VPP. The next section details the specific benefits and lessons learned from implementing a distributed VPP in USVI, offering valuable insights applicable to the wider Caribbean region.

US Virgin Islands (USVI) VPP Study

The US Virgin Islands, a Caribbean archipelago with three main islands — St. Croix, St. Thomas, and St. John — faces energy challenges commonplace across the Caribbean. The territory heavily relies on imported fossil fuels for electricity generation, resulting in high electricity costs averaging $0.41 per kWh for the 87,146 inhabitants.[2] That is roughly 2.8 times higher than the US national average.[3] The electricity grid across the territory has also been vulnerable to numerous disruptions, particularly after it was severely damaged by Hurricane Irma and Hurricane Maria in 2017.[4]

Despite these challenges, USVI has ambitious renewable energy goals, aiming for 30% renewable generation capacity by 2025, as mandated by Act 7075 (The Virgin Islands Renewable and Alternative Energy Act of 2009),[5] and over 50% by 2027.[6] VIEO is responsible for implementing energy policies, administering federal grants, and promoting renewable energy adoption through various incentive programs, and it is actively pursuing a 100% renewable energy study (VI-100) to guide this transition.

The electricity sector in USVI is driven by several key stakeholders. The vertically integrated utility Water and Power Authority (WAPA) is responsible for the generation, transmission, and distribution of power on the three islands. The Virgin Islands Public Services Commission acts as the regulatory authority, overseeing utility rates and service quality standards and approving major infrastructure investments. Independent power producers contribute additional generation capacity to the grid, while a growing number of DERs — primarily rooftop solar and battery systems owned by residents and businesses — are transforming the energy landscape.

USVI's energy landscape has been profoundly shaped by a confluence of factors, including a heavy reliance on imported fossil fuels, a vulnerable grid infrastructure susceptible to natural disasters, and a strong desire for energy independence. Following the introduction of net metering in 2009 through Act 7075, early adoption of solar PV was encouraged,[7] allowing residential and commercial customers to generate their own electricity and sell excess power back to the grid at the retail electricity rate. However, the initial program's 15 megawatt (MW) territory-wide capacity limit was quickly reached by mid-2017, signaling a need for a more comprehensive approach to DER integration.

Before this approach could be implemented, Hurricanes Irma and Maria, two of the most devastating Category 5 hurricanes to hit the Caribbean, made landfall across USVI in September 2017.[8] These storms caused widespread damage to the territory, leaving some residents without power for up to five months, and requiring upward of $795 million of aid from the Federal Emergency Management Agency to support recovery efforts.[9] The hurricanes damaged over 90% of WAPA's aboveground power lines and over 20% of its generation capacity,[10] underscoring the fragility of the centralized electricity system and emphasizing the need for resilient, locally generated energy solutions.

The extended power outages, already-high electricity costs, and a general wariness of the grid's reliability further fueled interest in DERs, particularly solar PV and battery storage. Residents and businesses seeking energy independence and a more reliable electricity supply, and incentivized by rebate programs for renewable energy systems,[11] installed DERs in large numbers to provide backup power and to mitigate the impact of future grid disruptions.

Given the post-hurricane public interest in DER systems, USVI implemented a temporary net energy billing (NEB) program in late 2021.[12] Although the NEB program introduced some modifications to the original net metering framework, such as a different compensation mechanism, a new grid access charge, and monthly credit reconciliation, it generally followed the net metering model by continuing to incentivize DER adoption. The NEB program, intended as a temporary solution to facilitate quick and orderly interconnection post-hurricane, has nonetheless spurred significant growth of DERs in USVI, driven by a growing awareness of the benefits of renewable energy and a desire for greater energy independence.

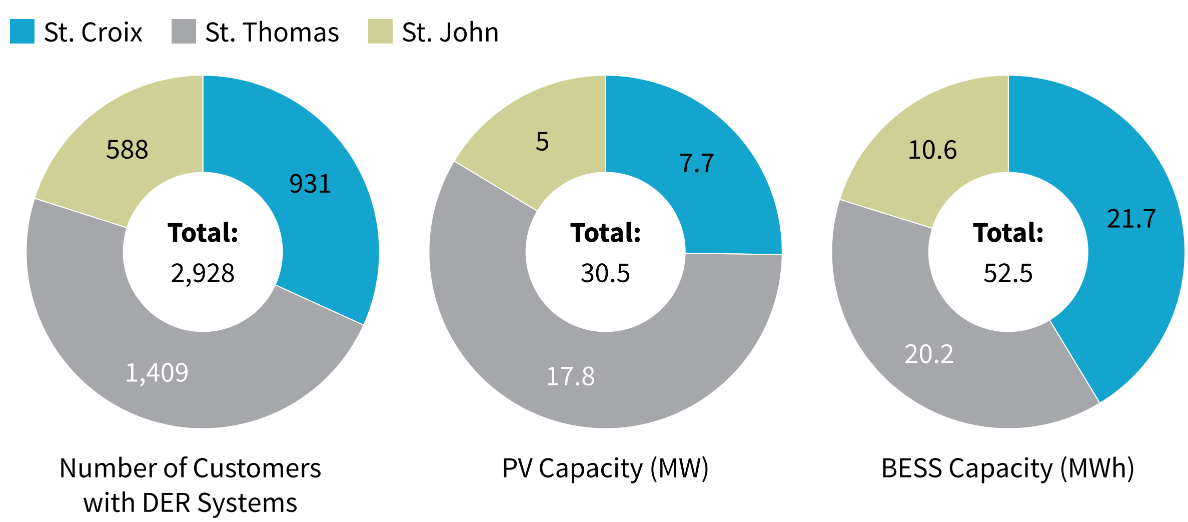
The NEB program streamlined the permitting process, with VIEO playing a central role in managing documentation and data flow between WAPA and the Department of Natural Planning and Resources, which oversees environmental permitting, building code compliance, and coastal zone management for energy infrastructure projects, including DERs within USVI.

This streamlined process has facilitated a rapid DER system rollout in the past few years. Between 2017 and 2024, distributed solar capacity increased at an average rate of 3.4 MW per year, and distributed battery storage capacity grew by 7.0 megawatt-hours (MWh) per year in USVI. In 2024, there were an estimated 2,928 electricity customers with operational DER systems across St. Croix, St. Thomas, and St. John. The total distributed solar PV capacity across the territory is 30.5 MW, while the total distributed battery storage capacity is 52.5 MWh, as shown in Exhibit 3.

In 2024, WAPA's installed generation capacity was 258 MW, serving a peak demand of roughly 105 MW. Therefore, USVI's distributed solar capacity alone was 11.8% of utility-installed capacity and 29% of peak demand. This highlights the large contribution DERs can play in achieving USVI's 2030 renewable generation goal.

Exhibit 3

Estimated DER customer count and distributed solar PV capacity (MW) and BESS capacity (MWh) in USVI in 2024, by island



RMI Graphic. Source: RMI analysis

Although the growth of DERs in USVI has been significant, realizing their full potential requires a more holistic approach to grid management. Integrating increasing numbers of DERs into the current grid infrastructure, originally designed for a centralized system, presents several challenges. These include potential issues such as load defection, limited solar PV hosting capacity, grid congestion, and voltage fluctuations, which would compound current grid challenges. However, these challenges also represent a significant opportunity. By developing an integrated and coordinated VPP program, it is possible to harness the territory's DERs to address these grid challenges and unlock a range of broader benefits.

To explore this potential, RMI worked closely with VIEO to conduct a comprehensive VPP study for USVI that assessed the technical feasibility, economic viability, and broader benefits of implementing a distributed VPP program. The analysis examined how varying levels of solar and battery energy storage penetration could be integrated into a VPP to support and reshape the USVI electricity system over a long-term horizon and on a day-to-day basis. The study evaluated several scenarios against a business-as-usual base case to achieve four main objectives:

- **Quantify the long-term economic, environmental, and grid stability benefits of VPP deployment**, including reduced generation costs, decreased fossil fuel reliance, improved frequency regulation, optimized line loading, and reduced emissions across the islands.
- **Analyze day-to-day VPP operational impacts,** including the ability to influence utility dispatch of fossil fuel generators, lower overall fuel consumption, and provide critical grid services during outages caused by generator shutdowns and rotating blackouts.
- **Identify optimal DER integration levels** that maximize benefits while accounting for technical and regulatory constraints. This assessment examined how increasing DER adoption would affect VPP performance under low-, medium-, and high-penetration scenarios, with consideration of both penetration levels and the geographic distribution of participating DERs.
- **Inform policy and planning decisions** by providing actionable insights for policymakers, utility planners, and regulators on the long-term benefits and costs of VPP implementation. These insights will guide future strategies for DER integration, VPP development, grid modernization, and energy resilience in USVI.

This analysis not only addressed immediate grid management challenges but also evaluated the potential for VPPs to enhance resilience against natural disasters, improve energy security, and create more equitable distribution of energy benefits across the USVI population through lower electricity bills and increased clean energy access.

The first crucial step for the USVI VPP study was a comprehensive DER landscape assessment of existing distributed solar PV and BESS assets in USVI. Data on registered DERs in USVI was obtained from three main sources and cross-referenced to develop three final DER master lists for each island:

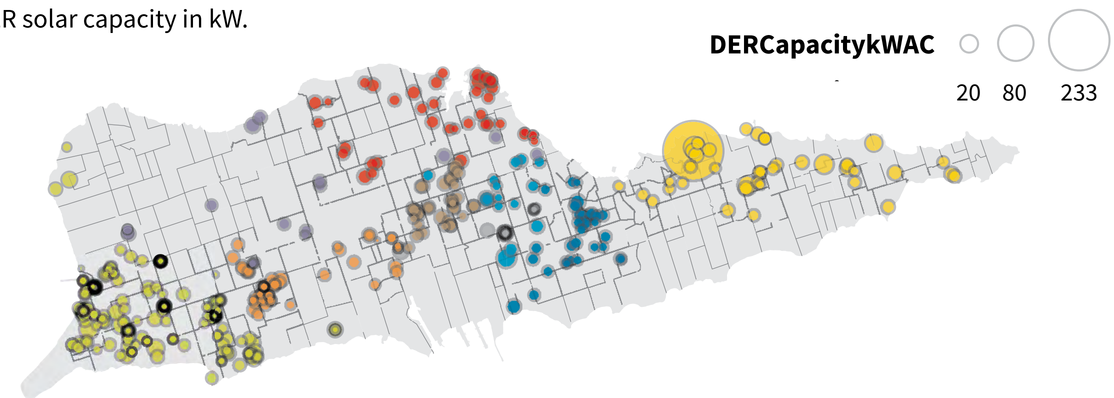
- The Net Energy Metering Master List contained capacity and location data for distributed solar PV and wind energy systems up to 2017.
- A registry from VIEO provided a partial listing of customer solar PV and BESS installed and registered after 2020.
- Geospatial data from a 2022 USVI interconnection study contained capacity and location data for customer solar and wind systems.

The coordinates of all DER systems were superimposed onto a map of USVI's distribution network to visualize the distribution feeders each DER was connected to throughout the territory. Exhibits 4 and 5 show that DERs are almost evenly distributed across St. Thomas and St. Croix, with the former having a noticeably higher density than the latter. On St. John, seen in Exhibit 5, DERs are primarily situated in the populated areas on the west (Cruz Bay) and east (Coral Bay) of the island.

Exhibit 4

Location of DERs on the island of St. Croix

The color of the bubble represents the feeder the DER is located on, and the size of the bubble represents the DER solar capacity in kW.



DER feeder locations

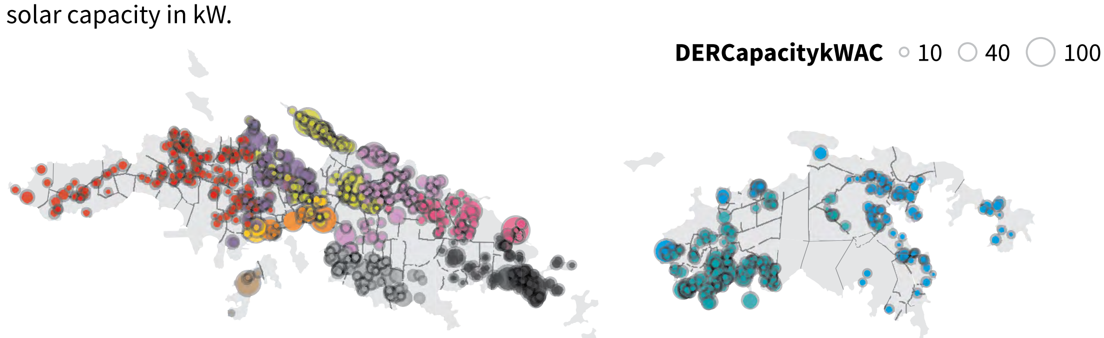
Feeder 02A, Feeder 03A, Feeder 04A, Feeder 05A, Feeder 06A, Feeder 08B, Feeder 09B, Feeder 10A, Feeder 10B

RMI Graphic. Source: United States Census Bureau, https://catalog.data.gov/dataset/tiger-line-shapefile-2019-state-united-states-virgin-islands-current-estate-state-based-shapefi; VIEO; RMI analysis

Exhibit 5

Location of DERs on the islands of St. Thomas and St. John

The color of the bubble represents the feeder the DER is located on, and the size of the bubble represents the DER solar capacity in kW.



DER feeder locations

Feeder 05A, Feeder 06A, Feeder 06B, Feeder 07A, Feeder 07B, Feeder 07C, Feeder 07E, Feeder 08A, Feeder 08B, Feeder 09C, Feeder 09E, Feeder 10B

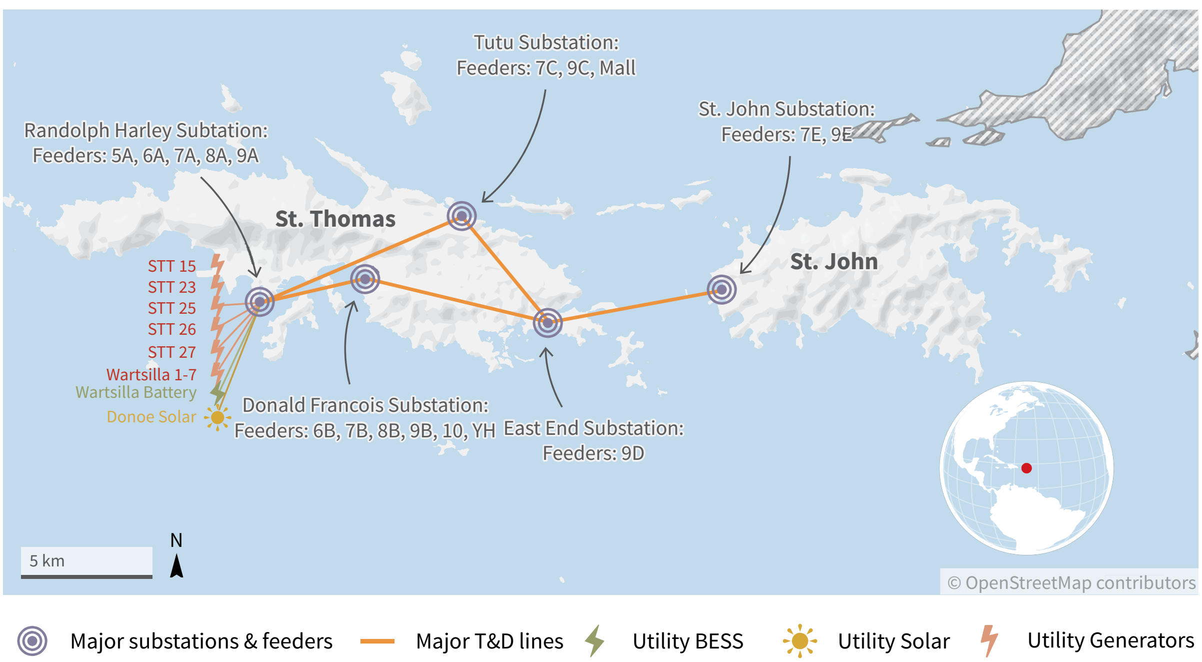
RMI Graphic. Source: United States Census Bureau, https://catalog.data.gov/dataset/tiger-line-shapefile-2019-state-united-states-virgin-islands-current-estate-state-based-shapefi; VIEO; RMI analysis

Once DER systems were identified, mapped, and clustered, a simplified model of the USVI grid was built out in PLEXOS, a powerful energy modeling software from Energy Exemplar.[13] The USVI electricity grid is divided into two separate systems: the St. Thomas–St. John (STT-STJ) interconnected grid and the St. Croix (STX) grid, serving the southernmost island of the territory. The key grid components of both systems were modeled and simplified in PLEXOS.

The STT-STJ grid, shown in Exhibit 6, features four major substations on St. Thomas and one on St. John, which is interconnected to St. Thomas by an undersea transmission line. All utility-scale generation on the STT-STJ grid, including fossil fuel generators, a utility-scale solar PV system, and a BESS, connect to the Randolph Harley substation on St. Thomas. Fifteen smaller feeders distribute electricity across St. Thomas and St. John.

The STX grid, shown in Exhibit 7, includes two major substations (Richmond and Midland) and 11 feeders. Utility-scale generation on STX includes four fossil fuel generators at the Richmond substation and a planned solar-plus-battery storage system at the Midland substation, expected to commence operation in 2026. Finally, the distributed solar and battery storage systems across USVI were added to the PLEXOS model and connected to their respective feeders.

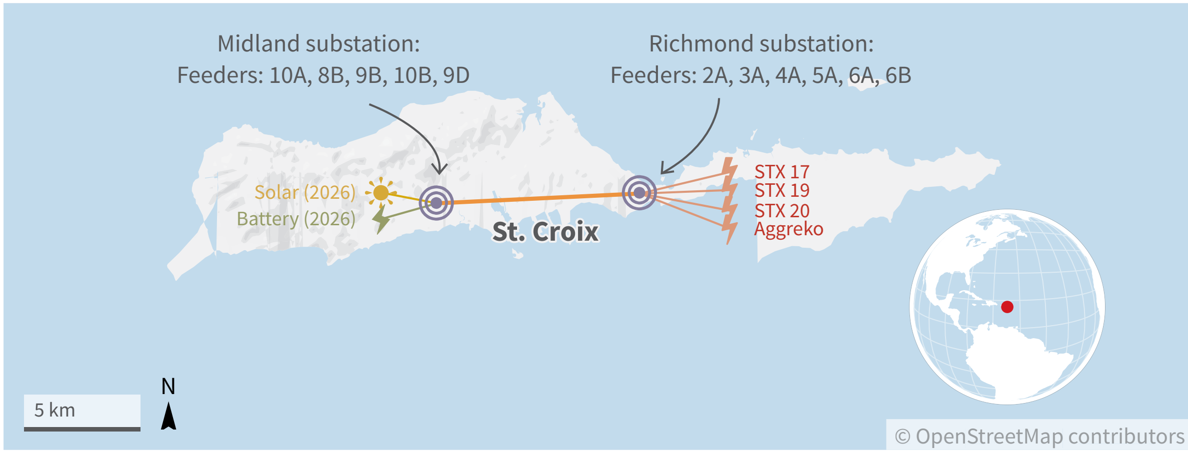
Exhibit 6 **Simplified grid topology on St. Thomas and St. John**



RMI Graphic. Source: US Virgin Islands, VIEO

Exhibit 7

Simplified grid topology on St. Croix



Major substations & feeders — Major T&D lines — Utility BESS — Utility Solar — Utility Generators

RMI Graphic. Source: US Virgin Islands, VIEO

As part of the PLEXOS analysis, unique scenarios were created, each exploring a different potential future for VPPs in USVI with varying levels of DER penetration. The scenarios were built as follows:

- A base case or business-as-usual scenario modeled a future in which no VPP efforts are undertaken and all DERs installed in USVI remain as individual, disconnected systems. Therefore, the effective capacity of the VPP is 0 MW of solar and 0 MWh of battery storage.
- A low DER penetration scenario involved interconnecting only the existing DER assets into a VPP, with no future build-out of new DER assets, which could result from unfavorable policy and regulation for DER development.
- A medium DER penetration scenario involved the build-out of new DER assets in addition to existing DER installations in USVI. DER solar PV was allowed to expand to 50% of the *remaining* PV hosting capacity for each feeder, and DER battery storage was allowed to expand up to a rate of 0.6 MW/1.7 MWh per feeder. After the seven-year horizon, this resulted in a total DER solar capacity of 43.9 MW and a DER battery storage capacity of 32.4 MW/84.1 MWh.
- A high DER penetration scenario allowed greater DER build-out at a faster pace than in the medium DER penetration scenario. DER solar PV was allowed to expand to 100% of the *remaining* PV hosting capacity for each feeder, and DER battery storage was allowed to expand twice as fast as the medium DER penetration, at 1.2 MW/3.2 MWh per feeder. After the seven-year horizon, this resulted in a total DER solar capacity of 56.5 MW and a DER battery storage capacity of 45 MW/115.5 MWh.

A few sub-scenarios were also assessed, mainly exploring a VPP program on St. Croix only, and another program for the islands of St. Thomas and St. John. Once the scenarios were developed, they were simulated in the PLEXOS model through a seven-year-horizon, long-term (LT) expansion plan and a short-term (ST) plan modeling the electricity system over periods varying from one to three weeks. The LT and ST plans analyzed the performance and impact of the entire electricity system, particularly with the distributed solar and BESS operating as a VPP. The simulations produced a range of insights, including cost savings, fuel reductions, emissions reductions, and improvements in grid performance. The most concentrated analysis focused on assessing VPP savings and program costs to understand the economic case for a VPP.

USVI VPP study long-term (LT) analysis

The modeled electricity-system savings from implementing a VPP were calculated by considering the total system costs for each VPP scenario compared with those in the base-case scenario. The difference between the total costs in a scenario and the base scenario was the savings that the VPP offers. The total cost was defined as the sum of all fixed and variable costs for all generators (including batteries) and physical contracts in the region.[i] The VPP costs were calculated by quantifying the compensation costs according to the chosen VPP modality.

The VPP modality selected for USVI was a battery compensation program, where 60% of each battery's energy capacity was made available for a VPP program. Batteries enrolled in the VPP would provide energy services to the grid and be reimbursed at a rate of $0.20 per kWh, representing a cost for the VPP.[ii] The net benefits were then considered to be the difference between the total potential savings and potential costs of the VPP. These key economic results are presented in Exhibit 8.

Exhibit 8 **Key economic results (savings and costs) from the LT analysis**

	Base (2024/2025)	Low DER Scenario	Medium DER Scenario	High DER Scenario
Description	Business as usual: Existing DERs are not aggregated into a VPP.	Existing DERs are aggregated into a VPP but there is no new build-out of distributed capacity.	DER solar PV allowed to expand to 50% of remaining feeder capacity.	DER solar PV allowed to expand to 100% of remaining feeder capacity.
2031 VPP DER PV Capacity MW	0	31.5	43.9	56.5
2031 VPP DER BESS Capacity MW/MWh	0	19.8/52.5 (can match largest generator for 1.3 hours)	32.4/84.1 (can match largest generator for 2.1 hours)	45.0/115.5 (can match largest generator for 2.9 hours)
Annual Savings = total system cost reduction from base scenario		$15.4M (9.5% reduction)	$20.8M (12.8% reduction)	$26.1M (16.1% reduction)
Annual Costs = compensation to VPP participants for BESS provision at 20 cents /kWh		$2.3M	$3.0M	$3.6M
Overall Annual Benefits = difference between savings and costs		$13.0M (~$260 per household on USVI)	$17.8M (~$356 per household on USVI)	$22.5M (~$450 per household on USVI)

RMI Graphic. Source: RMI analysis

i The fixed charges include fixed operation and maintenance costs ($/kilowatt) for installed capacity, and the variable charges include variable operation and maintenance costs ($/kWh) for generation and fuel costs ($/kWh). Finally, other generator costs that are included in the total costs consist of start-up and shutdown costs, emissions costs, and abatement costs. The physical contracts represented the external generation and costs to acquire this generation — i.e., any power purchase agreements currently in place.

ii The VPP's cost model currently sets participant compensation at $0.20 per kWh, aligning with the solar net billing rate. However, this rate is conservatively low, especially given the territory's retail electricity rates, which are closer to $0.40 per kWh. To effectively incentivize customer participation, the compensation rate should balance utility benefits with sufficient motivation for participants. By setting a competitive rate, the VPP can ensure robust customer engagement, which is essential to maximizing its operational and financial value.

The results from the LT analysis demonstrate that, across all levels of DER penetration in a distributed, battery-based VPP, the net benefits are substantial. The costs associated with compensating participating assets in the VPP are significantly outweighed by the financial and operational gains, as summarized by the following takeaways:

- **Cost savings:** The low DER scenario delivered annual electricity-system savings of $15.4 million, representing a 9.5% reduction in total system costs. The high DER scenario produced annual savings of $26.1 million, or a 16.1% cost reduction.
- **VPP program costs:** The VPP costs, largely driven by compensation for battery storage assets in the VPP compensated at $0.20 per kWh, ranged from $2.3 million to $3.6 million annually in the various scenarios.
- **Overall benefits:** The annual net benefits ranged from $13 million in the low DER scenario to $22.5 million in the high DER scenario. This translates to an annual benefit of $260 to $450 per household in USVI. This is in addition to other valuable benefits not assessed in this financial analysis, such as avoided costs associated with utility generator spinning reserves, which could add an additional $100,000 to $300,000 in annual savings.

In addition to direct financial savings in the LT, the VPP also provides critical nonfinancial benefits that contribute to a more resilient, efficient, and sustainable grid. These benefits, though not always captured in standard cost-benefit analyses, have far-reaching implications for the long-term reliability and stability of the power system, including:

- **Enhanced grid reliability and resiliency:** The distributed nature of VPPs, combined with the ability of DER assets to respond in real time, allows for more flexible grid operations. In the event of outages or extreme weather events, VPPs can help maintain critical power supply, making the grid more resilient to disruptions.
- **Frequency and voltage regulation:** Battery-based VPPs can provide essential grid services such as frequency regulation and voltage support, helping stabilize the grid and prevent blackouts or brownouts, especially during periods of peak demand or grid stress.
- **Reduced line loading and lower transmission and distribution (T&D) infrastructure costs:** By generating power closer to where it is consumed, VPPs reduce the load on T&D infrastructure. This can lower the need for expensive upgrades or maintenance to existing grid infrastructure, further enhancing the financial case for VPP integration.
- **Discouraging load defection:** A well-structured VPP can encourage customers to remain connected to the grid by offering compensation for their participation in grid services, reducing the incentive for load defection. This helps utilities maintain a stable customer base and ensures better overall grid management.
- **Environmental benefits:** VPPs promote the integration of cleaner DERs such as solar and wind, contributing to decarbonization goals and reducing overall emissions. This environmental impact, though often difficult to quantify financially, aligns with broader sustainability objectives and reduces the region's dependence on imported fossil fuels.

Although the financial benefits of a distributed battery-based VPP — such as reduced fuel costs, generation savings, and deferred infrastructure upgrades — are significant, the nonfinancial advantages such as improved grid stability, reliability, and the potential for reduced emissions make VPPs an even more compelling solution in the long term. Together, these factors strengthen the VPP's overall value proposition and highlight the transformative potential of VPPs in modernizing the grid and enhancing energy security for USVI and other countries and regions considering similar deployments.

USVI VPP study short-term (ST) analysis

The ST USVI VPP analysis explored the support a VPP program could provide if the utility experienced generator outages. On multiple occasions in recent years, WAPA has had to implement rotational blackouts across multiple feeders when dealing with generator outages, sometimes lasting for a period of weeks.[14] These rotating blackouts are intended to distribute the impact of the generation shortfall across the customer base and minimize unscheduled or abrupt interruptions.

The ST analysis assessed whether the VPP could mitigate these rotational outages by dispatching interconnected DERs to support the grid when required. By optimizing the use of DER assets, a VPP aggregator could help reduce unserved energy and potentially eliminate the need for rotational blackouts altogether, thereby enhancing grid stability and minimizing disruptions to electricity consumers.

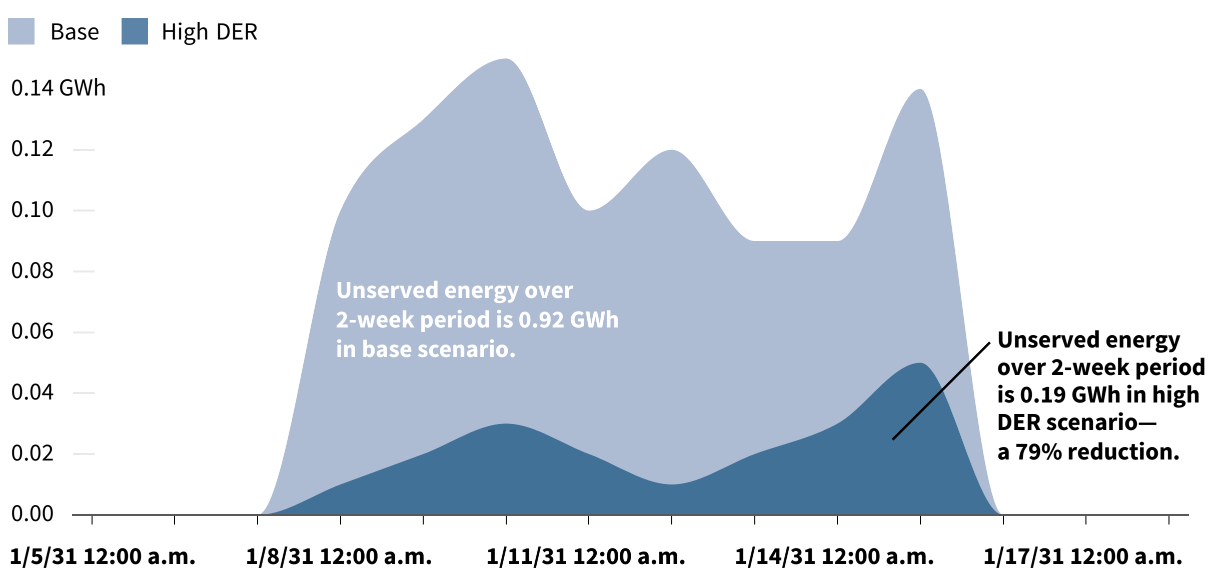
This analysis simulated the loss of the two most impactful generating units on each island for a period of nine days, rendering them unavailable for this designated period. The most impactful generators were identified based on their contribution to system generation during high-demand periods, as observed in the long-term scenarios. This analysis, commonly referred to as an N minus 2 analysis, is a standard reliability test for understanding the grid's ability to maintain stability following the loss of multiple generators.

The graph in Exhibit 9 illustrates the amount of unserved energy — essentially, the energy demand that would not be satisfied, leading to rotating blackouts — across the base case and the multiple VPP scenarios. The base case (light blue) shows a large amount of unserved energy, which is significantly reduced by implementing a VPP in the high DER penetration scenario (dark blue).

Exhibit 9

Unserved energy (GWh) in the base case versus multiple VPP scenarios

Measures high DER penetration case during a 14-day period in 2031, including nine days of generator failures



RMI Graphic. Source: RMI analysis

In the base case (i.e., no VPP program), 0.92 gigawatt-hours (GWh) of unserved energy was modeled during the generator outage period. By contrast, the high DER penetration scenario reduces unserved energy by 79% to only 0.19 GWh, showcasing the effectiveness of the VPP in maintaining grid reliability during major outages. This confirms the VPP's ability to reduce unserved energy and alleviate strained grid operations during generator shutdowns.

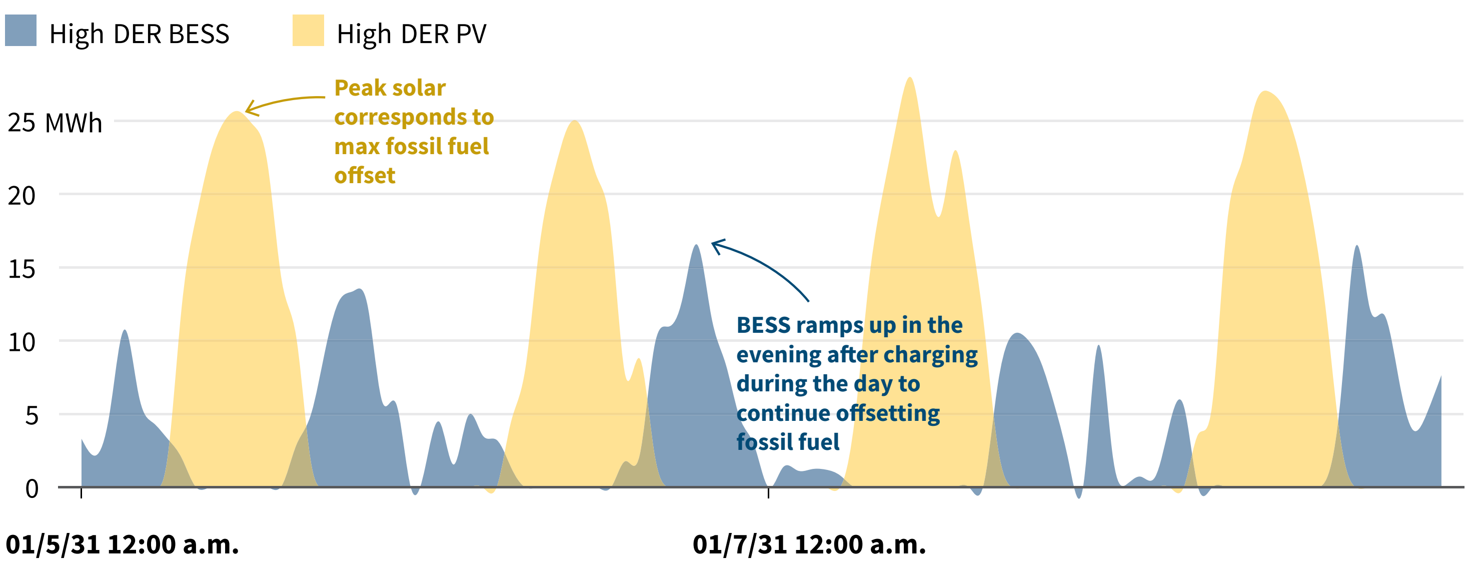
From a cost perspective, the base case resulted in a 15% increase in total system costs to the utility during the generator outages, compared with normal operations in the base case without any generator losses. However, in the high DER penetration scenario, this increase is significantly lower, at just 5.7%. In essence, the VPP's ability to mobilize a fleet of DERs in real time can significantly reduce the extent, duration, and costs of outages, allowing for a more resilient grid during critical periods of generator loss.

The ST analysis also aimed to understand how the VPP can offset fossil fuel generation and optimize the dispatch order of generation resources on a day-to-day basis during normal grid operations (i.e., without any generator outages). The analysis provided insights on how the VPP could help reduce overall fossil fuel consumption, lower system costs, and enhance the efficiency of the grid during typical daily operations, demonstrating the potential for the VPP to play a key role in long-term energy transitions for USVI. It analyzed how the VPP could shift dispatch away from traditional fossil fuel generators during peak and off-peak periods, particularly by using solar and battery storage assets.

Specifically, during daylight hours, the interconnected DERs in the VPP provided substantial generation to the grid, reducing the need for fossil fuel generators and creating daily dips in fossil fuel generation. During the evening peak hours, the energy stored in the interconnected BESS was dispatched to manage peak loads, further offsetting the need for fossil fuel–based generation, enhancing grid flexibility, and creating the nightly dips in fossil fuel generation. These generation patterns can be seen for the VPP high DER penetration scenario in Exhibit 10 during a four-day period.

Exhibit 10 **DER generation in the VPP high DER penetration case**

Measures a four-day period in 2031 in the ST study



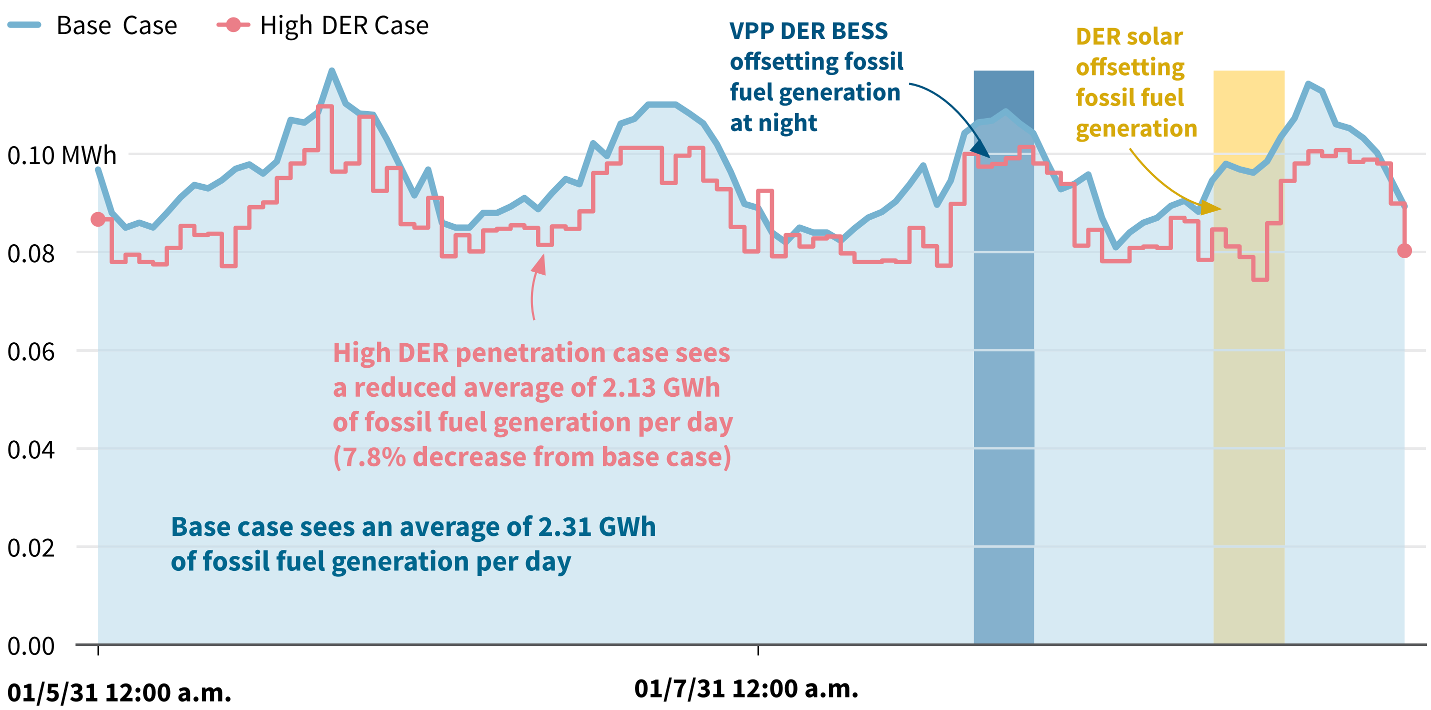
RMI Graphic. Source: RMI analysis

The DER generation seen in Exhibit 10 in the high DER penetration scenario was able to directly offset fossil fuel generation in the base case over that same four-day period, illustrated in Exhibit 11 (see next page). The base case (blue line and shaded area) showed consistently higher fossil fuel generation compared with the high DER penetration scenario (pink line). Furthermore, the dark blue and yellow shaded areas highlight examples of how the DER assets, as part of the VPP, work to actively offset fossil fuel generation.

In the high DER penetration scenario, fossil fuel generation reduced by 7.8**%** compared with the base case. The daily electricity system cost savings of around $424,000 associated with these operational improvements, a 12.3% reduction, are equally impressive. These savings are driven by reduced fuel consumption, lower generator wear and tear, and the efficient utilization of renewable resources. This highlights the VPP's ability to displace fossil fuel generation, in nearly every instance, by effectively integrating renewable energy sources and battery storage.

Exhibit 11 **Fossil fuel generation during normal operation**

Over a four-day period in 2031



RMI Graphic. Source: RMI analysis

The comprehensive analysis of VPP implementation in USVI reveals significant potential benefits across multiple dimensions. The study demonstrates that a coordinated VPP approach would deliver substantial financial returns, with net annual benefits ranging from $13 million in the low DER penetration scenario to $22.5 million in the high DER scenario. This translates to annual savings of $260–$450 per household across the territory.

Beyond the quantifiable financial advantages, the study highlights critical nonfinancial benefits that strengthen the case for VPP implementation. The VPP framework would enhance grid stability and reliability while empowering consumers to participate actively in the energy system, helping discourage load defection. Additionally, the reduced reliance on fossil fuels would contribute to meaningful emissions reductions, aligning with broader sustainability goals.

Particularly noteworthy is the VPP's contribution to grid resilience. By mobilizing a distributed fleet of energy resources in real time, the VPP can significantly mitigate the extent, duration, and costs of outages during critical periods of generator loss. This capability is especially valuable in the island context, where grid vulnerabilities can have outsize impacts on communities and economic activity.

The analysis further demonstrates the VPP's operational effectiveness, showing its ability to displace fossil fuel generation throughout daily operations by roughly 8%, reducing costs by more than 12%. Through intelligent coordination of renewable generation and BESS, the VPP optimizes resource utilization across the grid, reducing fuel consumption while maintaining reliable service.

Although USVI presents a compelling case study for VPP implementation, the insights gained from this analysis have significant implications beyond its shores. The shared challenges of island energy systems — from limited land availability to high imported fuel costs and climate vulnerability — make these lessons particularly relevant across the wider Caribbean region, and internationally as well. As neighboring island nations pursue their own clean energy transitions, the technical approaches, regulatory frameworks, and community engagement strategies developed in USVI can serve as valuable blueprints, adaptable to the specific contexts and needs of diverse Caribbean communities facing similar energy resilience imperatives.

Expanding VPPs across the Caribbean Region

Many island nations in the Caribbean have lower levels of DER penetration than USVI. However, uptake of DERs is proliferating across most countries for several reasons: rapidly declining costs of DER assets, high electricity prices, underperforming grid reliability, acute vulnerability to natural disasters and extreme weather events, and the desire for greater energy independence. These factors combine to create a compelling business case for residential, commercial, and industrial electricity customers in Caribbean island nations to invest in DER assets, with solar PV and BESS being the most popular.

Recognizing the benefits of DERs, some Caribbean countries have already instituted policy incentives that encourage electricity customers to purchase DERs and participate in utility- or regulator-managed DER programs that compensate them for electricity exported to the grid. Other countries are at an earlier stage, focusing on piloting DER programs without any consideration for aggregating the power of these assets.

The USVI VPP study demonstrates that implementing sensible regulations and policies to enable VPPs and harness DERs can lead to significant benefits for energy systems in small island nations. The lessons learned from the USVI study can be applied across all countries, regardless of their DER penetration today. Island nations with a moderate amount of existing DER systems already have one key VPP element in place: the assets. They should consider the best ways to advance the other core elements of successful VPP programs as well as policy and regulatory framework revisions to facilitate the implementation and operation of VPPs. Island nations with lower DER penetration can apply learnings from other jurisdictions to develop robust and strategic frameworks that facilitate the uptake of DERs while keeping innovative applications like VPPs in mind.

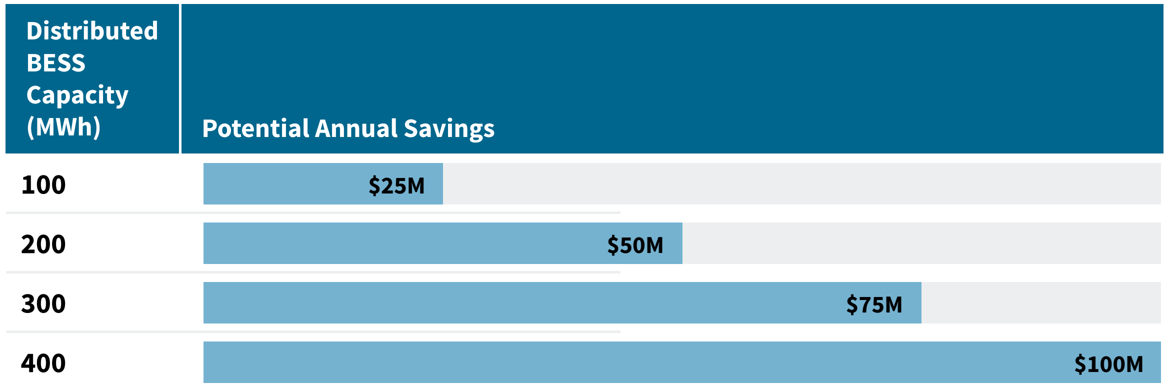
Current trends indicate that DERs will play a significant role in the regional energy transition; therefore, decision makers can act proactively to leverage these DER assets in VPPs for the sustainability and modernization of their energy systems. The following insights highlight key takeaways that stakeholders can consider in their efforts to transform the energy landscape in their respective countries, particularly by developing and implementing VPP programs to provide optimal value to the grid and its electricity customers.

Shared energy challenges in the Caribbean

The challenges in USVI's electricity sector that can be addressed by VPPs are common in several other Caribbean countries. Most countries in the region depend heavily on imported fuel for energy and therefore deal with high fuel costs and volatility of the global market. These high fuel costs translate to high electricity costs, with many rate structures in the region incorporating a fuel surcharge that allows the electric utility to recoup a portion of the money spent on fuel. In fact, at an average rate of US$0.34 per kWh,[15] Caribbean countries have some of the highest electricity costs in the world.

By leveraging renewable energy generation, this need for fuel can be reduced, lowering electricity costs and limiting exposure to fuel price volatility. The USVI study showed the potential for a reduction in system costs of 10% to 16% with the use of a VPP, and a savings rate of $250,000 per MWh of installed battery storage capacity. Exhibit 12 shows the estimated savings a utility can achieve for various levels of DER penetration.

Exhibit 12 Potential VPP savings at different levels of DER penetration connected to a VPP



RMI Graphic. Source: RMI analysis

The ability of modern BESS to rapidly discharge power makes them particularly valuable for the provision of spinning reserve capacity, which is traditionally met by fossil fuel generators. These fossil fuel generators are kept running so they can quickly ramp up if needed when there is a sudden change in electricity demand or if another generator unexpectedly goes offline. This is an important factor for grid reliability, as utilities must balance supply and demand at all times, while preventing outage events and load shedding that can occur as a result.

Because of their isolated grids and limited options for external interconnection, best practice for island electricity grids is to have a spinning reserve capacity equal to the two largest generators (i.e., N minus 2 policy), but this equates to large amounts of expensive fuel consumption. Instead, utilities often implement an N minus 1 policy (i.e., spinning reserve capacity equal to the single largest generator) or choose to strategically manage their generation capacity in order to keep costs down and load shed when needed. This has an impact on grid reliability, which in turn adversely affects home and business operations.

With distributed BESS — and, to some extent, solar as well — aggregated into a VPP, the spinning reserve capacity that must be met by fossil fuel generators can be reduced, cutting fuel and operation and maintenance costs for the utility and providing savings to electricity customers. As demonstrated in the USVI study, a VPP can help mitigate the incidence of outages and unserved load during emergency grid events, when traditional spinning reserve would usually be required.

Including DERs in VPPs can also help address issues faced in the electricity sector of Caribbean countries as they deal with the effects of climate change. Hurricanes are increasing in frequency and intensity, with wind speeds trending upward.[16] The hurricane season of 2024 also marked the ninth consecutive year of above-average activity.[17] Additionally, heavy rainfall can cause landslides and flooding, which is exacerbated by gradual sea level rise due to climate change. These deleterious events pose a serious threat to electricity generation and transmission and distribution infrastructure.

Strategic use of DERs in these circumstances can provide power to the most critical facilities, aiding recovery and preventing loss of life in the aftermath of these disasters. The effects of climate change are acutely felt in the Caribbean, with increasing ambient temperatures and predominantly warmer-than-usual temperature anomalies from mid-2023 through 2024.[18] This increasing heat has driven up peak electricity demand as utility customers increase their usage of cooling equipment like fans and air conditioning. Many regional electric utilities have reported record-high peak demands during these periods of extreme heat.[19]

This unprecedented demand can strain aging grid infrastructure, prompting the need for costly upgrades. The support that VPPs can provide in demand-side management is therefore valuable in helping defer these upgrades and improve the quality of the power supply.

In the Caribbean, DERs and renewable energy technologies, in general, have not traditionally been viewed as resources that can reliably support grid function. However, VPP programs, especially those incorporating battery storage, flip this narrative on its head. Strategic DER asset aggregation and management via a VPP can reduce fossil fuel consumption for electricity generation, lower electricity costs, and increase grid resilience. As Caribbean countries continue transitioning their energy systems, DERs will become more prevalent and will become a key resource for addressing these challenges.

Guidelines for VPP program design in the Caribbean

VPP program design in island nations should adhere to the same core principles exemplified in other jurisdictions while also accounting for the unique characteristics of each country. Because VPPs are in their relative infancy in the Caribbean, it is crucial to remain flexible and open to different approaches to ensure that the programs are effectively designed to meet their intended objectives.

Due to their small scale, island nations can obtain new insights rapidly, allowing for quicker revisions and improvements to programs. Furthermore, as with any new venture, stakeholder engagement is key and should be central to the program design process. Finally, each island's specific electricity-sector dynamics will introduce nuances based on its unique context, and these should be embraced to tailor solutions that are relevant and impactful. Some core principles for designing VPP programs in the Caribbean include:

1. Maintain adaptability to the evolving landscape

As highlighted in the National Renewable Energy Laboratory's 2024 Annual Technology Baseline, the costs of residential solar PV and BESS systems have been decreasing since 2022 and are projected to remain on a downward trend over the next 25 years.[20] These costs are also declining considerably in the Caribbean, despite being buffered by cost premiums associated with lower volumes and shipping and handling costs. For example, in 2023 Grand Bahama Power Company signed a power purchase agreement at a rate of $0.09 per kWh for a 9.5 MW solar PV plant,[21] lower than the regional 2020 average levelized cost of energy[iii] estimate of $0.11 per kWh.[22]

Renewable energy technology prices are declining for residential and commercial installations as well. Around 2015, residential solar PV installed costs in some Caribbean countries ranged from $2,000 to $2,500 per kW, whereas prices in 2025 range from $1,200 to $1,500 per kW. Residential battery storage prices have similarly seen a radical cost decline with costs of $1,600 to $2,000 per kWh for BESS five years ago compared with $300 to $750 per kWh in 2025.[23] As technology prices continue to decline, electricity customers increasingly will be motivated to procure DERs, not just to lower electricity costs, but also to enjoy reliable electricity during normal operations as well as backup power during grid outages.

iii The levelized cost of energy (LCOE) refers to the present value of the costs of an energy project distributed over the energy generated by the project over the project lifetime.

To ensure optimal and equitable deployment and use of DERs, a robust policy and regulatory framework needs to be in place. Island nations can proactively develop this framework to help them navigate through early-stage challenges that may arise as more DERs are installed. This can include creating new policies or updating existing ones to target the effective use of DERs in the electricity system, for example in VPP programs.

New policies will need to consider the increasingly important role of AI, including the benefits and risks of increased AI applications to enhance VPP operations. As described in *VPP Background*, AI algorithms can forecast weather patterns, anticipate changes in demand, and coordinate DERs enrolled in a VPP for optimal delivery of VPP services. Policies and regulations must therefore adapt to the changing landscape to capitalize on improving technological advancements while safeguarding the security and privacy of VPP participants and key operators, such as the VPP aggregator and electric utility.

Without a progressive framework, decision makers run the risk of implementing inefficient programs that can discourage participation and lead to load defection — a situation in which electricity customers fully or partially self-supply their premises (e.g., by installing sufficient distributed generation), thereby limiting their electricity consumption needs from the grid. Load defection represents a missed opportunity to harness a valuable grid asset and can lead to inequitable cost distribution across the utility customer base.

2. Harness the unique environment of a small island nation

An adaptable approach to VPP program design is also supported by the small scale of island nations. Smaller populations, fewer stakeholders, and more localized electricity systems allow for a narrower scope of observations, facilitating rapid feedback, which is valuable for VPP program improvement. Successes, deficiencies, new opportunities, and other learnings can be identified relatively quickly to further refine programs and propel the advancement of the technology.

Hawaiian Electric is one example of an island utility that has made use of these characteristics to advance the use of DERs in its electricity mix. The electric utility has offered several customer renewable energy programs in the past,[24] with programs such as Customer Grid-Supply Plus and Net Energy Metering Plus building off predecessor programs. Insights gained from previous programs helped the utility develop the two new long-term DER programs, one of which allows customers to provide grid services from their home battery systems,[25] much like a VPP. Continuous optimization of VPP programs in Caribbean island nations can provide an opportunity for them to become leaders of this modern technology in the Global South, showcasing their innovative capacity and serving as models for other jurisdictions.

3. Seek a customized VPP solution for each country or jurisdiction

Although it is helpful to learn from the efforts of other regions, it is important to avoid wholesale duplication of DER and VPP programs. Although similar at the macro level, local electricity sector dynamics and needs can differ significantly across Caribbean countries. For example, some islands might place the greatest priority on improving or maintaining very high energy reliability to support their economies, while others might focus more on reducing their dependency on imported fuels. VPP programs should therefore be tailored to each island's local context, applying lessons learned from other regions while also leveraging the data and information available locally.

For example, the optimal length of a contract term for a cost-effective VPP program capable of attracting wide participation depends on the energy economics of the jurisdiction in question. Similarly, prospective VPP participants may have varying preferences for enrollment, compensation, and modes of participation in different jurisdictions. The priority needs and objectives that the VPP programs are intended to address in the near term and long term should be defined in the initial planning stages of the process and guide the rest of the VPP program design.

Example objectives for VPP programs include reducing outages by using a VPP to provide power to the grid when needed and reducing fuel usage by displacing spinning reserve with aggregated battery storage capacity from a VPP. The priorities and challenges in each country's electricity sector will help inform the specific elements of VPP programs that can be adapted from other jurisdictions and the unique applications that should be employed. This is where a collaborative approach among key stakeholders is helpful to ensure that solutions implemented address the concerns of the electricity system.

4. Ensure stakeholder collaboration for effective VPP program deployment

VPP program design and implementation require the collaborative efforts and alignment of multiple stakeholders to ensure effective deployment. Collaboration among the utility, regulator, electricity customers (particularly prospective VPP participants), and any third-party VPP aggregators or service providers is valuable in overcoming barriers in policy and regulatory frameworks, technical systems, and market structures. Issues such as administrative or technical capacity constraints can be highlighted in the planning stages, and preemptive solutions, such as training and partnerships with third parties, can be implemented.

Additionally, awareness of gaps in customer understanding, as it relates to the technology or program, are crucial so that they can be addressed and VPP program participation can be encouraged. A collaborative approach is also useful in creating an enabling environment for VPPs and maintaining the momentum of VPP programs. For instance, the development of streamlined regulatory processes and attractive compensation schemes that meet customer needs can incentivize participation and reduce the risk of load defection.

Similarly, clearly defined technological requirements from the utility and VPP aggregator can facilitate easy enrollment of participants and seamless integration with the utility's dispatch platform while maintaining cybersecurity standards. Stakeholder collaboration is therefore essential for the early identification and addressing of potential obstacles as well as development of favorable VPP programs.

Policy and regulation for VPPs in the Caribbean

The USVI study reviewed VPP programs and policy frameworks in Hawaii, Puerto Rico, Vermont, and Western Australia, identifying eight key best practices, shown in Exhibit 13, that could inform the development of VPP regulatory environments in the Caribbean. These practices emphasize the importance of DERs as a core element of VPPs and advocate for comprehensive, flexible systems that can support grid stability while maximizing the potential of DERs. Although the best practices focus on VPPs, they also allow for the integration of other DER programs, promoting a holistic approach to optimizing the value of these resources.

Exhibit 13 Best practices and recommendations for VPP regulatory frameworks

Best Practice	Recommendation
1. Establish grid service needs	Highlight the most critical grid service needs to be addressed by customer-sited DERs to inform program development. Knowing the grid service needs that are required in the short and long term will help to ensure that any program developed is fit for purpose.
2. Develop long-term DER plans	Include the need for long-term, strategic planning for DERs in regulatory framework. This planning can inform development of programs that leverage these assets and benefit the utility and ratepayers.
3. Establish an overarching demand response program	Regulators and utilities should collaborate to develop an overarching demand response or DER program. An overarching program will provide flexibility for different types of subprograms or tariffs that can be used to carry out demand-side management activities.
4. Develop competitive procurement processes for third-party providers or aggregators	Adapt procurement framework to allow for contracting of independent third parties to provide programs or aggregate customer DERs for use in a VPP. Having the proper frameworks in place will allow for ease of participation and faster uptake of the program.
5. Implement fair and sustainable compensation/ incentives that reflect the value that DERs bring to utilities	Consider compensation mechanisms based on quantifiable factors, such as the cost of avoided generation. Consider use of up-front incentives to allow for equitable program participation. These mechanisms will encourage new and continued participation in programs. Premiums can also be applied to compensation for emergency grid events.
6. Determine appropriate cost-recovery mechanisms	Collaborate with the relevant stakeholders to determine how costs incurred by the utility can be recovered. Sufficient consultation can allow for development of solutions that are acceptable to all from the outset and hence minimize the risk of regulatory delays later in the program.
7. Regularly evaluate effectiveness of demand response/VPP programs	Consider regular use of an analysis that weighs customer benefits against costs to ensure that programs are cost-effective for the utility and customers. Regularly assessing the cost-effectiveness of programs can allow for early detection of disparities or areas for improvement within the program.
8. Ensure cybersecurity and data protection protocols are in place	Establish requirements for cybersecurity and data protection in a customer DER program and enforce these requirements on aggregators and program providers. These requirements will assuage the privacy and security concerns of all stakeholders involved in the program. Alternatively, in the early stages, programs can avoid the cybersecurity risk through scheduled dispatch operation when devices do not need to be managed in real time.

RMI Graphic. Source: RMI analysis

Key takeaways for Caribbean islands

As demonstrated by the USVI study, VPPs can address the challenges shared by many Caribbean islands. VPPs, especially those using battery storage, offer an effective solution to reduce fuel consumption, mitigate outages, lower electricity costs, and improve grid resilience during emergencies. The design of VPP programs in the Caribbean should draw on successful models from other regions while also remaining cognizant of the unique characteristics of each island. Given the nascency of VPP development in the region, flexibility and openness are critical to refining VPP programs, using the rapid feedback available in these small island systems.

Furthermore, each island's specific energy priorities should inform the design of solutions tailored to their needs. Stakeholder engagement and collaboration are essential for the successful deployment of VPPs in the region. Best practices extracted from other jurisdictions can also provide useful insight into policy and regulatory strategies for creating an environment that enables the full potential of DERs, including VPPs, to be captured. Ultimately, VPPs represent a modern solution to optimally harness the DERs that will play a key role in the Caribbean's energy transition and can be a defining feature of the region's future energy system.

Conclusion

The transformation of island energy systems from centralized, fossil fuel–dependent infrastructure to resilient, decentralized, distributed networks is not just an aspiration — it is becoming a necessity. As demonstrated through the detailed analysis of the USVI case study, VPPs offer a compelling pathway to achieve this transformation. VPPs can deliver substantial economic benefits while simultaneously enhancing grid stability, improving resilience, and accelerating the transition to renewable energy.

The USVI analysis revealed that VPPs can generate annual net benefits of up to $22.5 million for the territory's electricity system, translating to significant household savings while reducing daily fossil fuel generation by approximately 8% and cutting costs by more than 12%. Perhaps more importantly, VPPs provide critical nonmonetary benefits, including enhanced grid reliability, improved resilience during extreme weather events, and increased empowerment of electricity customers — all particularly valuable benefits in the island context.

As island nations in the Caribbean continue to tackle the intersecting challenges of high electricity costs, grid vulnerability, and climate change impacts, the lessons learned from the USVI case study offer a valuable blueprint for regional energy transformation. Although all countries will need to adapt VPP program design and implementation to their unique context, the fundamental benefits remain consistent: reduced dependence on imported fossil fuels, enhanced grid stability, improved resilience to natural disasters, and accelerated progress toward clean energy goals.

By embracing VPP technology and establishing supportive regulatory frameworks, island nations can unlock a more sustainable and resilient energy future. This transformation will not only benefit electric utilities, individual electricity customers, and communities, but will also contribute to the broader goals of energy independence and climate resilience. The time for action is now, and VPPs stand ready to play a crucial role in this essential transition.

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