A Renewable Energy + Storage Base for the United States Virgin Islands:

Pre-Feasibility Report

October 2014

Island Energy Innovations, LLC.
Integrating Utility Scale Renewables

GridFlex

Confidential

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IEI-Gridflex *Renewable Energy + Storage Base for the United States Virgin Islands: Pre-Feasibility Report*. 2014.

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Executive Summary

Island Energy Innovations, LLC engaged Gridflex Services, LLC to examine the potential for shifting the electric power supply base of the United States Virgin Islands from one dependent on fossil fuels to one that relies on renewable energy for the majority of its need.

A detailed examination was conducted of the USVI's existing and forecasted electric power demand and supply, along with an analysis of the renewable resource and bulk energy storage potential. This evaluation was conducted to determine a plausible balance of energy resources that could achieve the greatest reduction in fossil fuel use while meeting firm power needs and maintaining operational reliability and grid stability. Reliable and accurate wind & solar data were used in conjunction with hourly WAPA load data for the analysis model.

The results suggest that it is technically and economically feasible to shift the islands' electric power supply to a far higher level of renewable resources than previously considered. Furthermore, it appears that this can be achieved with a minimum of curtailment to the wind and solar PV renewable sources.

Key elements of the supply system include the following:

- distributed or centralized solar PV plants totaling 105 MW in capacity.
- offshore wind off the southern coasts, in combination with onshore wind, totaling 110 MW;
- baseload renewable in the form of biomass (14 MW) andwaste-to-energy (10 MW);
- bulk energy storage in the form of pumped storage hydropower on St. Thomas and St. Croix to provide multi-hour energy management using "closed loop" configurations (20 MW each);
- a 5 MW battery energy storage system on each island to provide short-term power quality and regulation service;
- retention of the newer of the existing oil/multi-fuel units for firm back-up supply.

The above portfolios are estimated to reduce dependency on the fossil fuel supply for electric power to **16%** on St. Thomas/St. John and **8%** on St. Croix. Phrased another way, it appears feasible for the USVI to achieve a **nearly 90% renewable** energy supply by the year 2020.

While the capital investment required for the new supply base would be significant, the savings in cost of fuel would more than compensate for the cost, and the wholesale cost of energy to the island would decrease significantly. Preliminary figures indicate a territory-wide reduction in the cost of energy supply of **approximately 25%** below a projected cost of energy production based on the USVI Energy Road Map, even after accounting for conversion of combustion turbines to Propane (LPG). The reduction in CO2 emissions would be dramatic as well.

Follow up studies will be required to confirm the development feasibility for the various elements of the renewable and storage supply at the levels needed for the proposed shift, refine the economic and technical models, refine site selection; assess potential environmental impacts, and lay the ground work for development.

I. Introduction

The United States Virgin Islands are highly dependent on expensive, imported fuel oil for their energy supply. At the same time, the islands are naturally blessed with a variety of abundant renewable energy resources. In fact, encouraging wind energy resource assessments for the islands date back at least three decades. Ending their dependency on expensive imported fuel would not only have significant economic benefits for the USVI, but would make a contribution to reduction in greenhouse gas emissions. Climate change is a major concern to island territories and nations, and many Caribbean nations have developed plans for renewable energy development.

Over the past several decades, some effort has been made to understand and develop local renewable resources. Wind energy assessments date back to at least 1981[1], and various other alternative energy options have appeared in studies since. It has been established that the Virgin Islands are endowed with abundant renewable resource potential, and some of that potential has begun to be developed. Several utility-scale solar PV projects are in development under power purchase agreements with the Virgin Islands Water and Power Authority (WAPA), a significant biomass facilityis in late development stage, and wind projects are under negotiation.

These renewable energy projects still represent a relatively small contribution to the total energy mix, and the emphasis in recent utility planning has been on implementing energy efficiency measures while converting existing fossil fuel units to propane (Liquid Petroleum Gas, or LPG) to both reduce cost and reduce carbon emissions. While energy efficiency is a preferred strategy for lowering energy costs as well as greenhouse gas emissions, the current plan continues to rely on fossil fuels for the bulk of delivered electric power.[2] The relative slices of supply currently planned are shown in the charts below.

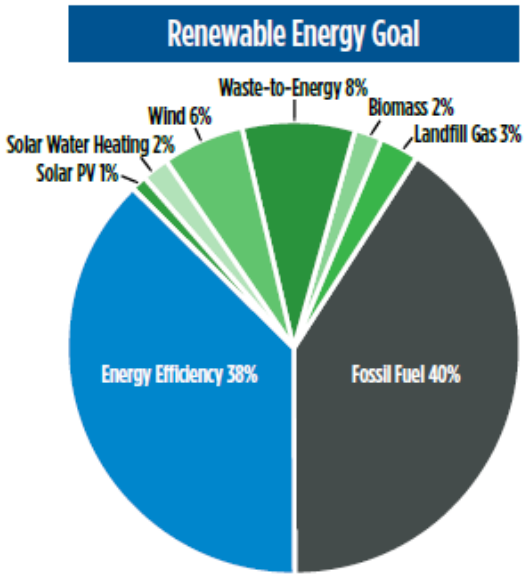


Figure 1. USVI Renewable Energy Goal

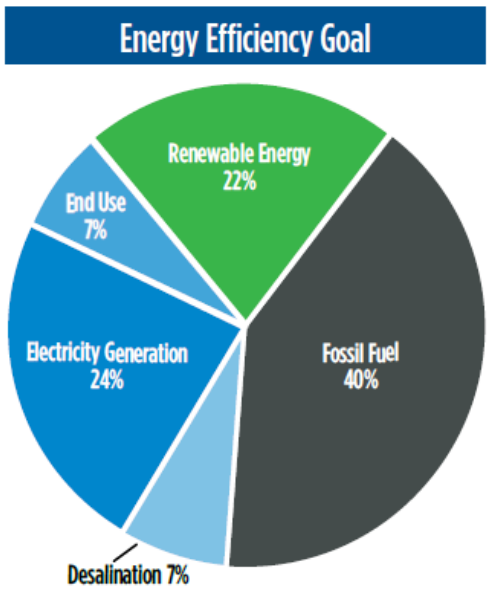


Figure 2. USVI Energy Efficiency Goal

[1] Southern Solar 1981
[2] EDIN 2011b; WAPA 2012b

The above distribution represents the "base case" that appears in NREL's "roadmap" analysis from 2011.[3] The Roadmap's *High Renewable Case* scenario shows only a 25% renewable energy contribution to the long-term goal.

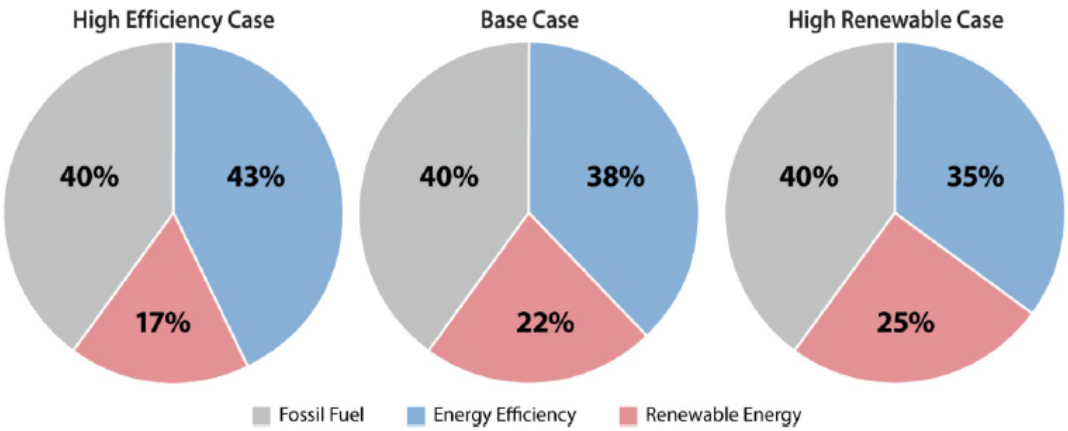


Figure 3. USVI Percentage of conventional fossil fuel generation, RE generation, and Energy Efficiency used to server the expected, business as usual 2025 fossil fuel demand across scenarios.

Developing and integrating a significant level of renewable resources poses particular challenges for island systems. Two of the best established technologies—wind and solar PV—are intermittent in nature, and wind in particular can be highly variable. The relatively constancy of the wind resource in the Caribbean helps, but there can be significant and rapid differences in wind output from moment to moment, depending on the location and size of the wind plants. With solar PV, clouds bring an element of intermittency that can cause even more rapid changes in output.

Due to the variable and intermittent nature of wind and solar PV, most utility systems have determined that there are technical limits to the level of renewable energy that they can absorb and manage. This figure ranges from 15% to 30% of installed capacity, depending on the nature, isolation, and flexibility of the system. However, this limit can be overcome. Strategies range from better wind forecasting to maintaining operational flexibility to incorporating energy storage into the system. In fact, some small systems have reached a nearly complete shift to renewable resources.

As this report will show, the U.S. Virgin Islands are in a very good position to achieve what only a few small island systems have achieved: shifting their energy supply base from being nearly 100% dependency on fossil fuel to drawing the majority of their energy from renewable sources. They can achieve this by (a) taking advantage of the natural complementarity between wind and solar PV, (b) developing a moderate amount of baseload renewable energy to complement the variable resources, (c) the use of bulk energy storage to provide multi-hour energy shifting, (d) the use of nearly instantaneous energy storage for moment-to-moment and "power quality" support, and (c) the retention of the newer and most efficient of their fossil base for back-up supply.

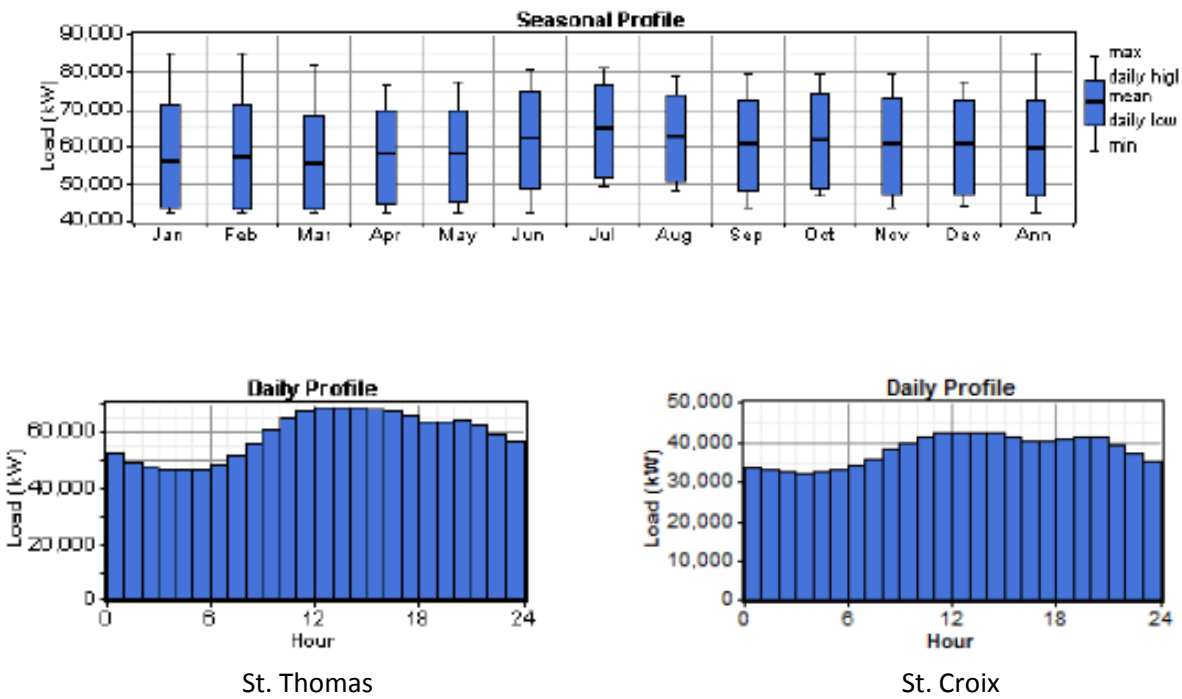
[3] NREL 2011a

In summary, these preliminary results indicate that the USVI have the necessary resources to develop a high sustainable, high renewable energy penetration, large-scale power supply system. Furthermore, the data suggests that this power system can be achieved economically within the next decade.

II. Electric Power Demand and Supply in the U.S. Virgin Islands

Electric power demand in the U.S. Virgin Islands is expected to grow very slowly over the foreseeable future. St. Thomas is expected to see an annual growth rate of 1% for both peak demand and gross energy, with St. Croix at 0.5%.[4]Peak demand on St. Thomas is currently at an average of 74 MW, with annual peak of 88megawatts (MW).[5]The corresponding figures for St. Croix are 50 and 55 MW, respectively.

Among Caribbean islands, the USVIhave relatively high load factors (ratio of average demand to peak demand), with a load factor of 71% for St. Thomas and 73.4% for St. Croix projected for the year 2016[6]**.** This means that demand doesn't exhibit the peaks and valleys like systems subject to wide daily temperature variations. The charts below indicate the seasonal variation (for St. Thomas) and the typical daily variations for St. Thomas and St. Croix.



St. Thomas St. Croix

Figure 4. USVI Typical Daily Load Profiles[7]

Load is currently met with a supply base consisting almost entirely of oil-fired generators, burning #2 diesel fuel oil. The current base consists of the following units, given by year of installation:

[4] WAPA 2013c
[5] WAPA 2013c; NREL 2011b
[6] WAPA 2012a
[7] NREL 2011b

St. Thomas' Randolph E. Harley Generating Station*

Year Installed	Unit & Type	MW	30 Year Date
1968	#11 Steam Turbine	18.5	1998
1972	#14 Peaker	12.5	2002
1973	#13 Steam Turbine	36.9	2003
1981	#15 Combined Cycle	20.9	2011
1985	#7 Peaker	2.5	2015
1993	#18 Combined Cycle	23.5	2023
2001	#22 Peaker**	24	2031
2004	#23 Peaker	39.5	2034
2012	#25 Peaker	22	2042
		200.3	

*Does not include Heat Recovery Steam Generators

** To be replaced in 2014 by a new LM2500 gas turbine

St. Croix'Estate Richmond Generating Station

Year Installed	Unit& Type	MW	30 Year Date
1967	#10 Steam Turbine	10	1997
1970	#11 Steam Turbine	19.1	2000
1981	#16 Combined Cycle	20.9	2011
1988	#17 Combined Cycle	21.9	2018
1994	#19 Peaker	22.5	2024
1994	#20 Steam Turbine	22.5	2024
		116.9	

We were not able to find any published target retirement dates for these units.

Average heat rates (the amount of fuel used for the required electric output) for the existing base are very high as shown in Figure 5(from WAPA testimony to the legislature in 2013.[8])

A 1994 document cites unit-specific heat rates that indicate the two oldest St. Thomas steam turbines operated at heat rates of about 14,000 to 16,000 Btu/kWh, and the two oldest St. Croix steam turbines

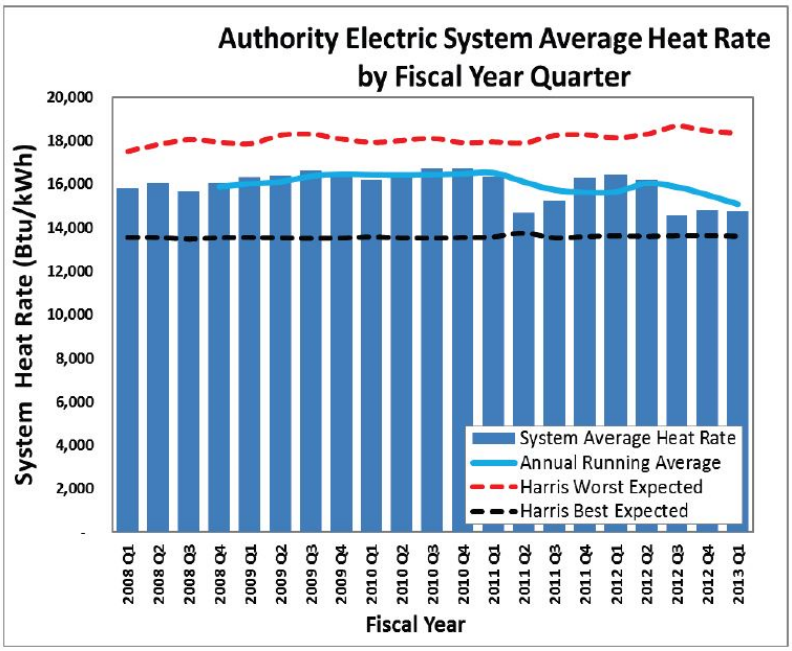


Figure 5. VI WAPA System Average Heat Rate

[8] Hodge 2013a

at 13,000 to 15,000 Btu/kWh. Combustion turbine heat rates were significantly worse – as high as 22,500.[9]

According to the 2013 Senate testimony, WAPA attributes high heat rates to its load characteristics. A specific contributing factor cited in NREL's 2011 roadmap analysis is the use of thermal energy for the MED (Multi Effect Distillation) desalination plants. These have recently been replaced by more efficient reverse osmosis systems, which should improve the heat rates.

Current Supply Cost

The USVI has the highest, or among the highest, cost of electricity in the Caribbean region. According to the October 2014 rate schedule[10], the fuel component of the energy charge per kWh is $0.378 resulting in a residential retail rate of $0.490 per kWh and a commercial retail rate of $0.52 per kWh. Out of its FY2014 budget, fuel costs represented $243,160,000[11], which equates to $.31/kWh of energy *generated*. Based on figures extrapolated from WAPA's audited 2013 financial statement[12], fuel costs per kWh may have been slightly higher that year.

As is shown Figure 6[13], the islands have been subject to significant price swings for imported oil, with an upward trend in costs. These have had a direct impact on electricity prices.

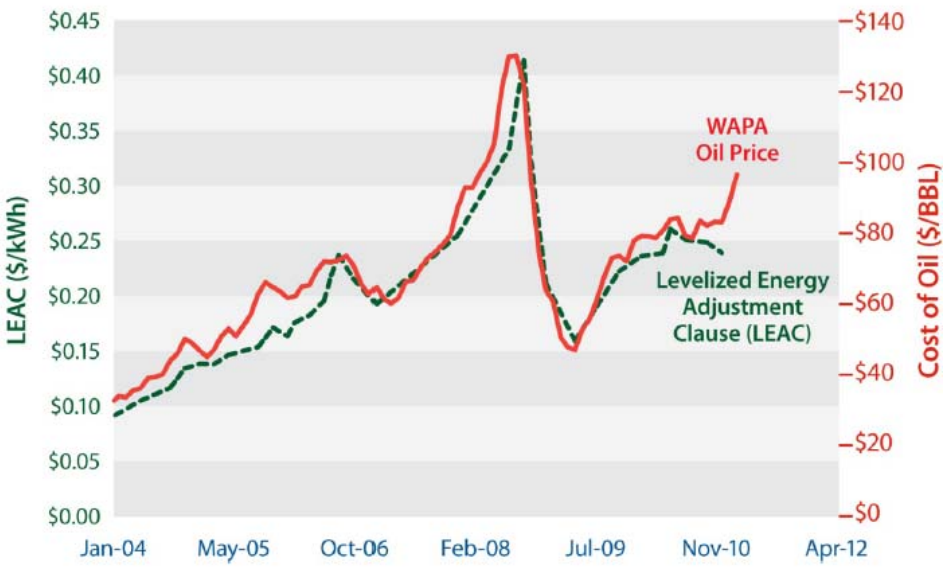


Figure 6. LEAC and Cost of Oil over time.

With regard to O&M costs, using WAPA's 2013 financial data, we have extrapolated the O&M cost at approximately $.04/kWh.

[9] ORNL 1994
[10] WAPA 2013e
[11] Hodge 2013b
[12] WAPA 2013f
[13] NREL 2011a

Propane and LNG Conversion

WAPA is currently preparing to modify most of its generating units to burn propane, with a target of conversion to liquid natural gas (LNG) within several years. Studies confirming the feasibility of conversion were first authorized in 2011, and included generator manufacturer GE. In July, 2012, WAPA reviewed the earlier studies and concluded that small-scale LNG conversion was feasible. RFQ's were issued in 2012 both for LNG conversion and for the supply of LPG as an interim fuel. LNG was seen as a longer-term solution: "Given the currently less developed state of small-scale LNG market, negotiations with the LNG respondents and the implementation of an LNG solution is likely to take longer than the LPG solution." [14]

Conversion was initially to begin in July2013, but is now expected to be complete in 2015[15].WAPA statements indicate an expected fuel cost reduction of 30%[16] based on a seven-year contract signed with propane supplier Vitol in 2013, with the possibility of 40% savings following a five-year amortization period.[17] Vitol is providing advance funding for tri-fuel retrofit of eight generating units.

Full conversion to LNG cannot begin until additional shipping and other infrastructure improvements are in place, which is expected to be after 2016.[13]However, there is significant uncertainty about the viability of this option, due to the (a) higher costs associated with shipping LNG to markets as small as St. Thomas and St. Croix and (b) the potential cost of constructing a LNG receiving terminal. This uncertainty increased after the closure of the HOVENSA refinery.[14]

If WAPA's projections for a 30% fuel price reduction are accurate, fuel costs may fall to about $.24/kWh. The 40% reduction figure cited above has not been validated. Even a local proponent of LNG conversion, Christiansted-based Quest LNG, suggests no greater than a 30% savings in their marketing material.[18]

Transmission

The transmission system on St. Thomas consists of three 34.5 kV feeders from three substations (Rehelio Hatchette, East End, and Tutu). There is also a 34.5 kV substation on St. John. Distribution voltage is 13.8 kV, with three distribution substations. Power is transmitted from St. Thomas to St. John via two 35 kV submarine cables, with a third available for emergency backup.

On St. Croix, nine feeders run from the Richmond generating station—three at 24.9 kV and three at 13.8 kV. St. Croix began upgrading its main feeder system to 69 kV in 2013.

System losses are significant, with a figure of 13% (St. Croix) and 6% (St. Thomas/St. John) as indicated in Roadmap Analysis.[19] With planned improvements, losses are expected to fall to 5% of energy sales on St. Thomas and 7.2% of sales on St. Croix by 2016.[20]

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[14] Hodge 2013a
[15] deJongh 2014
[16] WAPA 2013c
[17] Hodge 2014
[18] Quest LNG 2014

The following electric distribution maps here (St. Thomas above, St. Croix below) are drawn from NREL's 2011 wind integration study.[21]

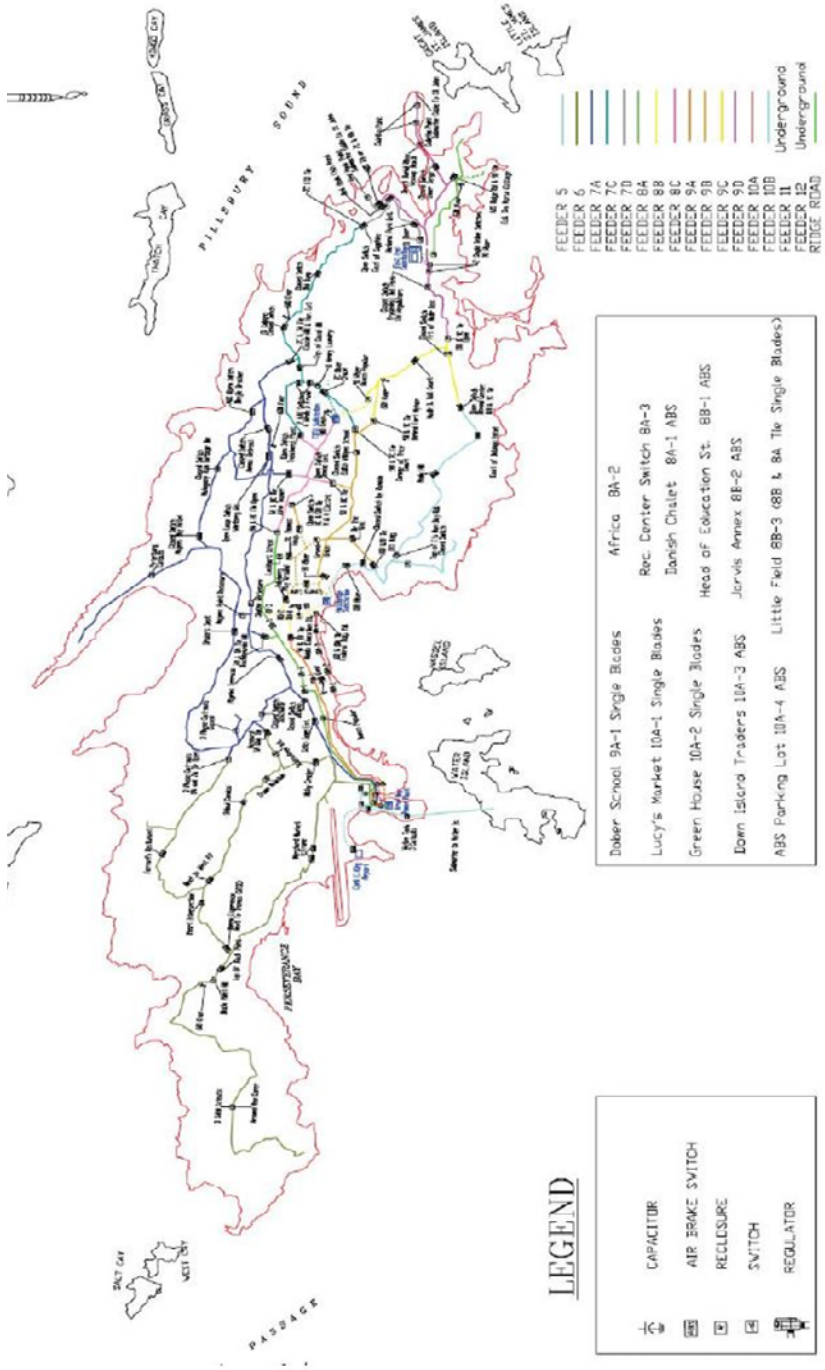

Figure 7. St. Thomas Electrical Feeders

[19]NREL 2010
[20] WAPA 2012a
[21] NREL 2011b

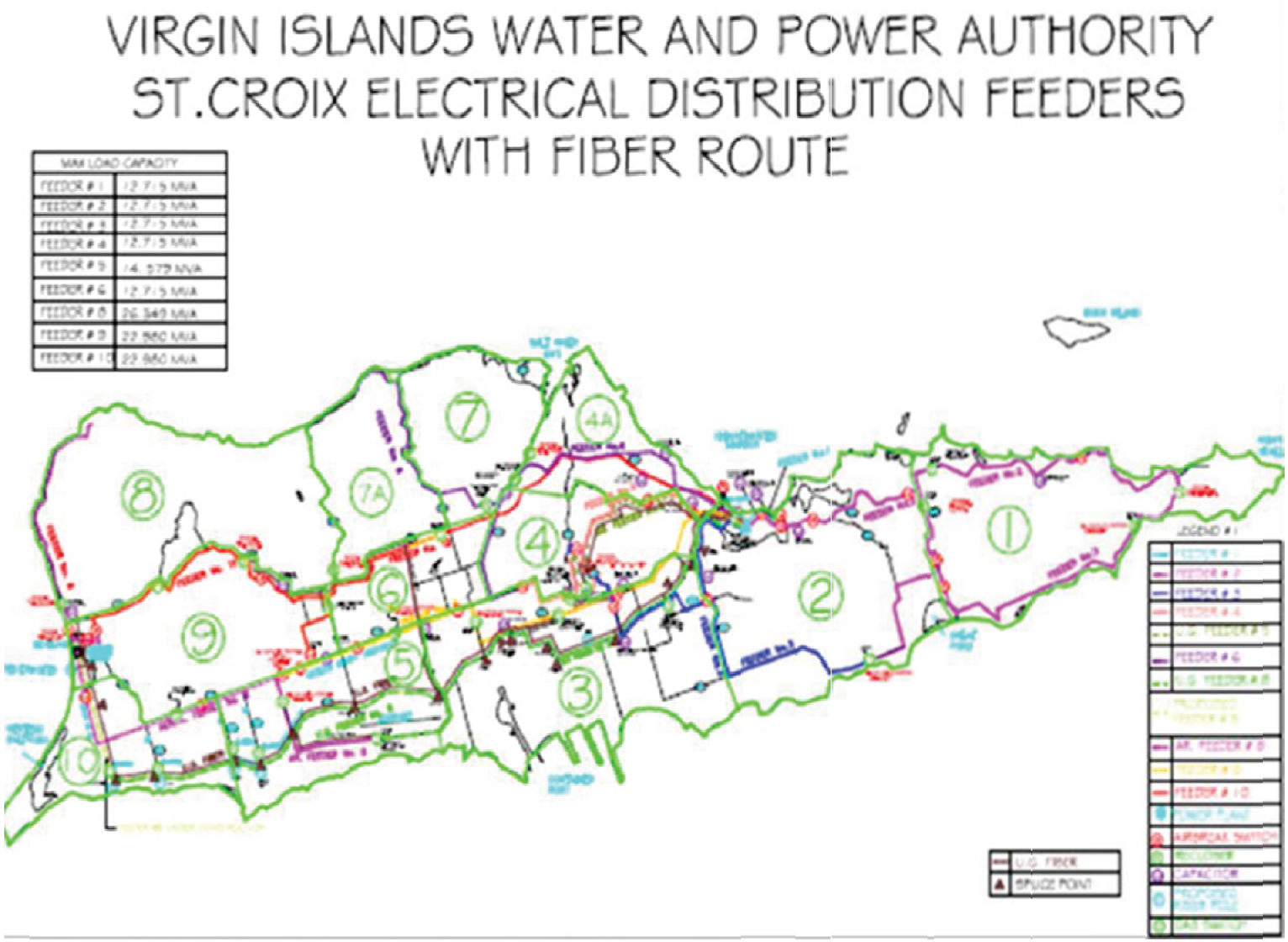

Figure 8. St. Croix Electrical Feeders

III. Renewable Energy Potential in the US Virgin Islands

The renewable resource potential of the US Virgin Islands has been under intermittent study for many years. The Water and Power Authority has issued a number of solicitations for renewable energy projects over the past decade. An RFP issued in 2004 for Renewable and Alternative Energy had to be suspended due to a jurisdictional conflict between WAPA and the Public Service Commission. A 2005 RFP resulted in the selection of a wind power bidder, but their proposal was withdrawn, reportedly over concerns about hurricane risk.[22] A 2007 RFP resulted in the selection of the Alpine Energy, LLC waste-to-energy (WTE) bids (see below for detailed discussion). A 2011 RFP for solar energy resulted in several contracts (see below as well). A 2013 RFP was issued to close a procurement gap from the 2011 process.

Wind

Published studies of the wind energy potential in the USVI date at least as far back as 1981, when the Southern Solar Energy Center commissioned a siting assessment and economic study under a DOE contract.[23] The study was very preliminary and relied on very limited data. This study concluded that there was "considerable promise" for utility scale wind, and suggested more detailed studies.

In 2005, in response to one of the earliest WAPA RFP's for renewable energy, a 19.8 MW project for St. Croix was selected for further negotiation. The project was said to have offered to meet WAPA's avoided cost for new generation, which was set by WAPA at $.11/kWh at the time based on an expectation of future efficiency improvements. Negotiations ended over issues of hurricane risk and liabilities.[24]

As part of the NREL/DOE Wind Power America program, NREL began wind resource modeling and validation at the 30m level. Validation was based on four measurement towers and two airports. The study produced 70m and 100m maps as well, but these were not initially validated. A 2008 report[25] estimated an all-islands technical potential of 346 MW at average 70m windspeeds of 6.5 to 7.0 m/s, 134 MW with windspeeds of 7-7.5 m/s, and 36 MW with speeds of 7.5-8 m/s. These figures are after exclusions for sensitive areas (national parks and St. Croix Marine Park). The estimated capacity

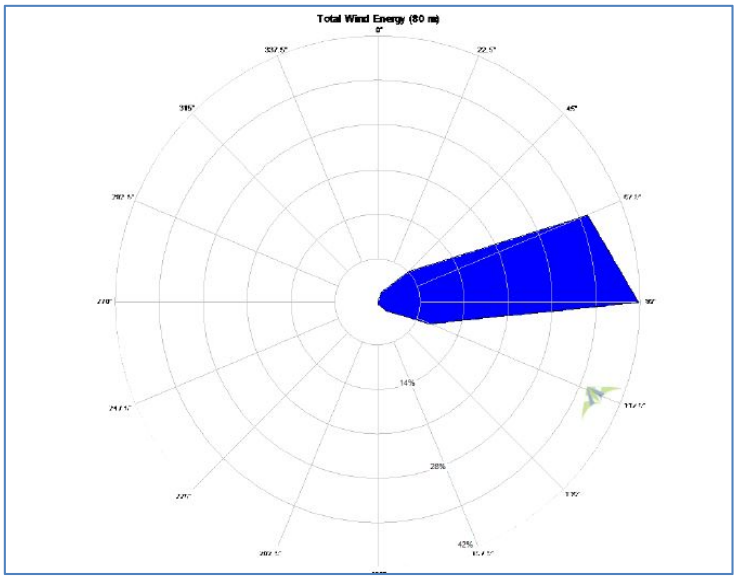

Figure 9. Predominant Wind Direction at Bovoni Point, St. Thomas

[22] Hodge 2013a
[23] Southern Solar 1981
[24] USDOI 2006
[25] NREL 2008

factors for the >7.0 m/s regime was >30%. The following highlights were reported:

- Good wind resource areas can be found on many exposed ridge crests and coastal areas.
- Strongest winds are seen from June through August and December-February, but this can vary somewhat from year to year.
- Diurnal (hourly variation) climate varies considerably (daytime maximum in most locations; slightly greater night time winds on highest ridge crests).
- Taller tower measurements and remote sensing (SODAR/LIDAR) needed to accurate characterize the wind resource at hub heights of modern turbines.

Low diurnal variation is advantageous for wind, as a relatively constant wind makes integration easier. Another advantage to USVI winds are that they tend to be unidirectional, as indicated by the wind rose.The USVI are within the tradewind belt characterized by prevailing winds from the east. This has positive implications for wind turbine arrays, as they can be spaced more closely in the crosswind direction.

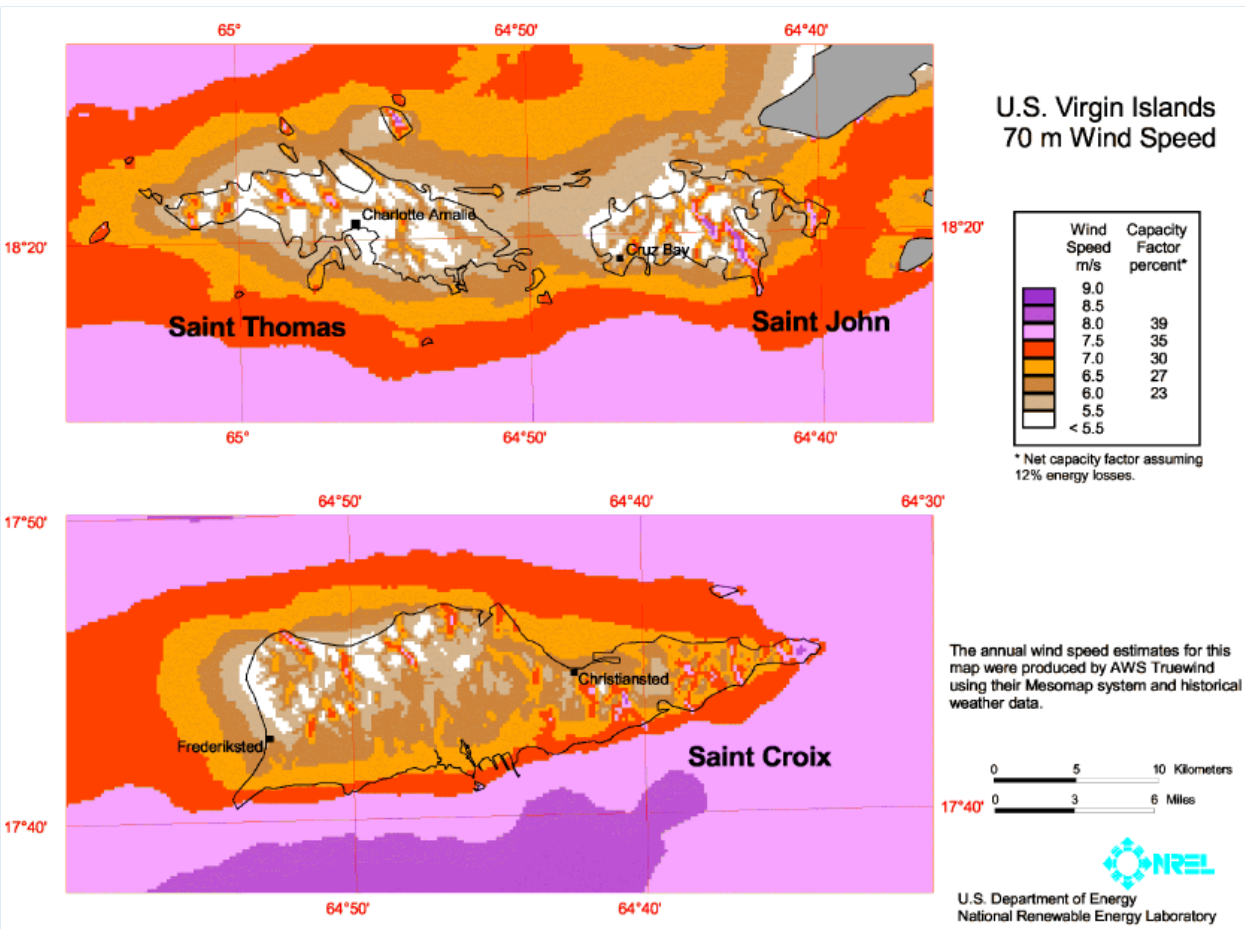

Figure 10. USVI 70m Wind Speed

NREL's 2011 analysis of the USVI "Energy Road Map" limited the potential wind capacity to 12 MW to 33

MW, depending on scenario, due to "potential land use impacts and possible siting challenges." The resulting Base Case assumed 22.5 MW of wind over the subsequent 15 years. Two sites in particular were emphasized: the Bovoni Landfill in St. Thomas, and the south shore of St. Croix, east of the HOVENSA refinery (see map below), due to the fact that both had already been industrialized and is generally considered to have some of the best “accessible” wind resource. Offshore wind was excluded from consideration due to the fact that it had not yet been deployed in North America.

Figure 11. Areas considered to have a high potential for wind development in the USVI (NREL).

NREL published a Bovoni-specific study site in 2012. The study focused on specific potential turbine placements and analysis using a variety of turbine models. Photo simulations were also prepared. Based on measured and modeled wind data, and using Vestas (Class II) and Vergnet turbines, estimated installed capacity at the site range from 5.5 MW to 13 MW.

21

Figure 12. Bovoni, St. Thomas Potential Wind Turbine Locations.

The estimated capacity factors were significantly better with the Vestas turbines, which would have higher hub heights and larger rotors than the Vergnet (the advantage of the latter being their special design for hurricane zones – see below for further discussion of hurricane considerations). Estimated net capacity factors for 80m hub heights for the Vestas V100 1800 and 2000 were 31% and 27%, respectively.

Levelized cost of energy was estimated at between $.10 and $.20/kWh, using then-appropriate capital cost assumptions.

Figure 13. Photo visualization of a multi-megawatt turbine with an approximately 420-ft tip height (taken from point E in Figure 12).

At the beginning of 2013, a tall tower was installed on the Bovoni Peninsula on the south shore of St. Thomas, with a measurement height of 58m. A high quality data set was published in early 2014. This data indicated higher average windspeeds than had been previously estimated for the site. The map below, developed by NREL as part of an updated analysis, indicates potential net capacity factors of 35-40%in better exposed portions of the Bovoni Peninsula. This was based on the use of a Vestas V100 1.8.

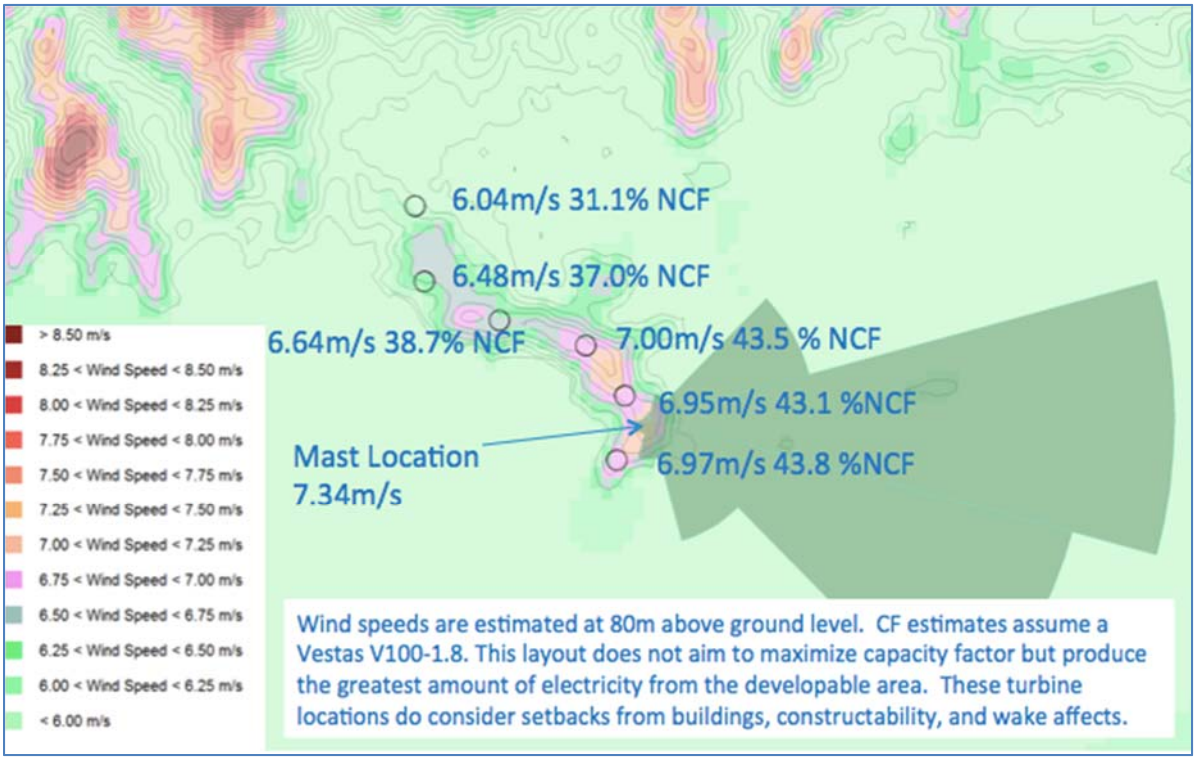

Figure 14. Bovoni Wind Speeds at potential locations.

Prior to receiving this map, Gridflex Services' own analysis of the data had indicated a net capacity factor of 38.4% with an 85m hub height. This is very close to the new NREL estimate.

Turbine selection should be considered closely when estimating the quality of USVI wind for energy production. Over the past several years, hub heights have increased and new models with larger rotor:generator ratios have been developed and placed into service. In fact, we can look elsewhere in the Caribbean for an example of the difference in output. Hutting[26] contrasts two windfarms on Curacao. One site is called Tera Cora, and the other is Playa Canoa. The Playa Canoa site has a remarkable 58% capacity factor, compared with the Tera Cora site's 35% capacity factor, in part due to the use of a larger rotor with lower rated wind speed, which provides a 40% increase in swept area per kW. (Playa Canoa also happens to have a 10% higher wind speed, and a lower level of turbine reliability).

With the hurricane risk in the USVI as a caveat (see below), the wind speeds on the island would appear to be well-suited for these types of turbines. The choice of turbine used in the NREL analysis – the Vestas V100 1.8 – is indicative of the potential of using the "stretched rotor" turbine, because its maximum output is 1.8 MW versus the 2.0 MW model. The power curve is designed to capture lower-end winds and peak out slightly earlier.

[26] Hutting KEMA

Onshore Wind Cost

Capital costs for onshore wind have fallen over the past several years. For modeling purposes, we use a figure of $2,500/kW, which is conservatively higher than what is used for larger projects in mainland markets.[27] O&M costs are roughly $25/kW-yr (combined fixed & variable). The capital cost figure should be contrasted with that of $3,600/kW used in NREL's 2011 "Road Map" analysis.

Offshore Wind

Offshore wind is now well-established, with the majority of installations in Europe but an increasing level of development in Asia and in the U.S. There are now 4,550 megawatts of offshore wind plant in operation. Advantages to the use of offshore wind vs. onshore include a great expansion of available space for installation, steadier and generally stronger winds, and greater amenability to very large turbines with better economy of scale, at lower required hub heights. The trade-offs are primarily higher capital cost and higher O&M costs (roughly double what onshore wind costs), along with technical challenges of interconnection.

The majority of installed offshore wind involves relatively shallow water (<100 feet in depth), but a growing number of offshore is being placed in deeper water, with new, floating turbine designs eliminating the need for shallow water. They can also be placed further out, reducing visual impacts (see below).

Offshore wind is an option not previously taken seriously for the USVI, with the exception of 10.5 MW project proposed by Ocean Offshore Energy, a partnership headed by Texas-based developer Herman Schellstede. The project would be located south of the Bovoni landfill in St. Thomas, and received tentative approval by the Public Services Commission in 2013.[28]

As the eastern coastal shelf with depths under 100 feet extends out at least one mile off the southern shores of both St. Thomas and St. Croix, it represents a potentially attractive complement to onshore wind. The number of turbines that would be required is relatively small, as the turbines would probably be larger than those use for land (a 112 meter diameter, 3 MW turbine has been assumed in the analysis to follow).

While the arrays in this case would be relatively close to shore compared to most new offshore wind farms, its smaller size would allow it to be positioned where it has the smallest impact on the viewshed. Shallowness of depth and proximity to shore also reduce installation and operating costs, as indicated by the multiplier factors in the Table 1.

[27] WECC 2014
[28] VI Daily News 2013a

Table 1. Impact of Depth and Distance for Offshore Costs

Water depth (m)	Distance from shore (km)							
	0-10	10-20	20-30	30-40	40-50	50-100	100-200	>200
10–20	1	1.02	1.04	1.07	1.09	1.18	1.41	1.60
20–30	1.07	1.09	1.11	1.14	1.16	1.26	1.50	1.71
30–40	1.24	1.26	1.29	1.32	1.34	1.46	1.74	1.98
40–50	1.40	1.43	1.46	1.49	1.52	1.65	1.97	2.23

Source: EEA (2009)

Environmental impact considerations for offshore wind are slightly different than for onshore projects. Of particular interest for study are the effect of pile-driving during construction on marine mammals, and impact on marine environments in general. Impacts on tourism and marine safety need to be considered as well. However, studies have shown that with regard to impact on tourism, "the evidence is ambiguous, and actual effects appear to be minimal or positive."[29] In fact, the foundations of offshore wind turbines can serve as artificial reefs, enhancing marine populations.[30]

Capital costs for offshore wind are at least double the costs for onshore, depending on turbine size, depth, distance, and other factors, although one source suggested that costs would be falling to as low as $2,191/kW by 2020.[31] This could be due to the trend toward larger turbines, which are now available in scales of 7 MW and larger. O&M costs are significantly higher as well. For our modeling, we've used a capital cost figure of $4,000/kW, with O&M at $35/kW-yr.

Visual Impact of Offshore Wind

With a likely distance from shore beginning at about a mile in the case of St. Croix, and 1-2 miles for St. Thomas, visual impact will be an important consideration. The following image portrays a visual simulation of offshore wind turbines at various distances from shore, beginning with a distance of two miles.[32]

[29] NREL 2013
[30] Langhamer 2012
[31] NREL 2012b
[32] Santee Cooper 2009

This photo simulation compares the visibility of wind turbines placed at varying distances from shore. Specifically, the turbines are depicted at distances, left to right, of 2 miles, 3 miles, 4 miles, 5 miles, 6 miles, 7 miles and 8 miles from the shore. Different light, wind and haze conditions could make them more or less visible. Photo credit: Santee Cooper

Figure 15 shows a simulation using a 90-meter diameter turbine at a distance of 2.2 miles.[33]

Figure 15. Photo Simulation of Hull Offshore Wind Power Project. Credit Renewable Energy Research Laboratory.

[33] Manwell 2007

The maximum realistic offshore potential for St. Thomas and St. Croix is not yet known. Visual impact and intersection with shipping lanes, potentially environmentally sensitive locations, and cost-to-performance ratio will set limits.

St. Thomas

Although there appears to be extensive potential for offshore wind south of St. Thomas, careful consideration would need to be given to specific visual impacts of various potential array sites. Distances of at least two miles should help, along with the north-south orientation of the arrays. The 13 arrays shown in the Renewable Supply Placement section of this report (below)represent a total of 156 MW–much larger than would be needed for a St. Thomas/St. John high-renewable portfolio.

St. Croix

The best place for offshore wind serving St. Croix is south and east of the industrialized area of the former HOVENSA refinery. The array portrayed in the Renewable Supply Placement section of this report (below) accommodates 16 x 3 MW turbines (e.g., the Vestas V112-3.0), or a total of 48 MW. If placed in four north-south oriented arrays of 4 turbines each, the windfarm would have an E-W length of 2.1 miles and a N-S width of 1.05 miles, using 5 x diameter crosswind spacing and 10 x diameter downwind spacing. Potential visual impact would have to be studied from various shoreline viewpoints. It may be possible to use fewer and larger turbines as well, which garners some additional economy of scale benefit and reduces the number of turbines contributing to visual impact.

Hurricane Risk to Wind Turbines

The potential impact of hurricanes on wind turbines has been a concern ever since windfarms began to be considered for hurricane (and typhoon) prone areas. The speed of sustained winds of a Class 5 hurricane (157 mph+) equal the peak gust "survival speed" of some Class I turbine models.Hurricane concern was cited by WAPA executive director Hodge as a reason for the termination of negotiations with a wind developer in response to a 2005 RFP. The bidder "could not commit that the wind turbines that were being proposed could withstand hurricane force wind."[34]

Figure 16 and Figure 17[35] show the historical track of major hurricanes through the Caribbean since 1960. The USVI are clearly in a hurricane risk zone. The most severe hurricane in modern times was Hurricane Hugo (1989), which crossed over St. Croix as a Class IV storm. Hurricane Marilyn (1995), although only a category 2-3, caused significant damage on St. Thomas. It should be noted that there are forecasts that the frequency of severe hurricanes may increase due to global warming.[36][37]

[34] Hodge 2013a
[35] Masters 2010
[36]Vickery 2008
[37] CARIBSAVE 2012

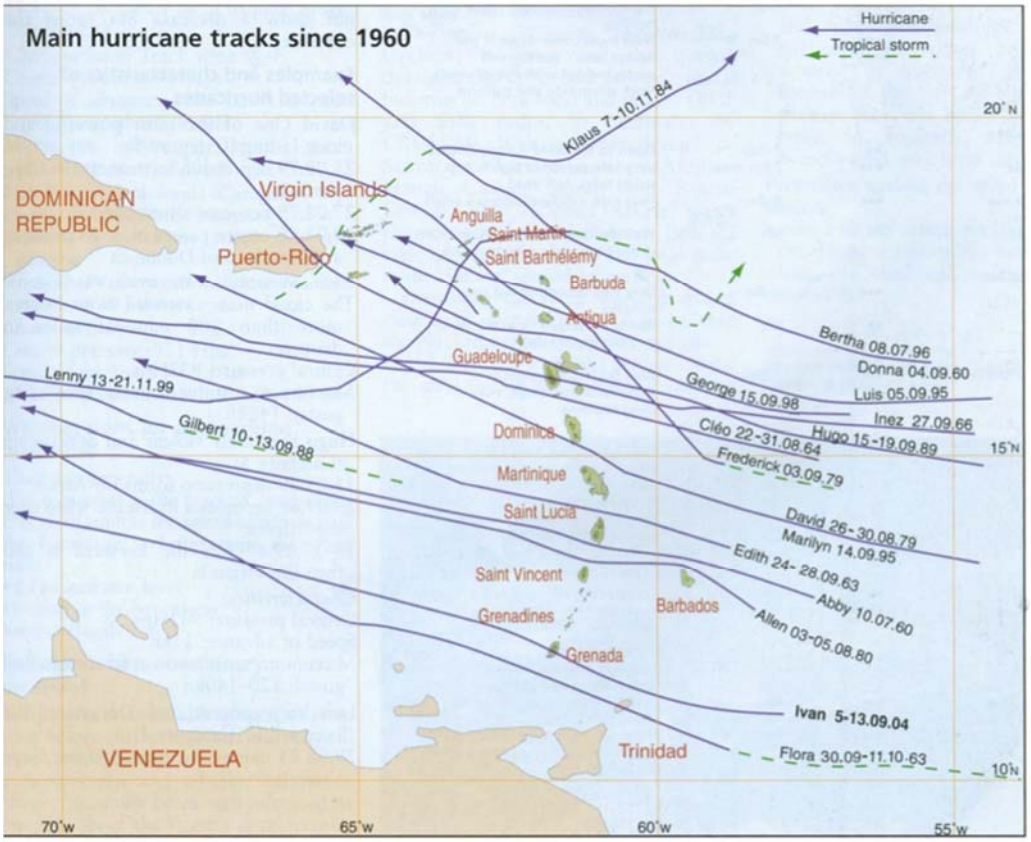

Figure 16. Caribbean Major Hurricane Tracks Since 1960.

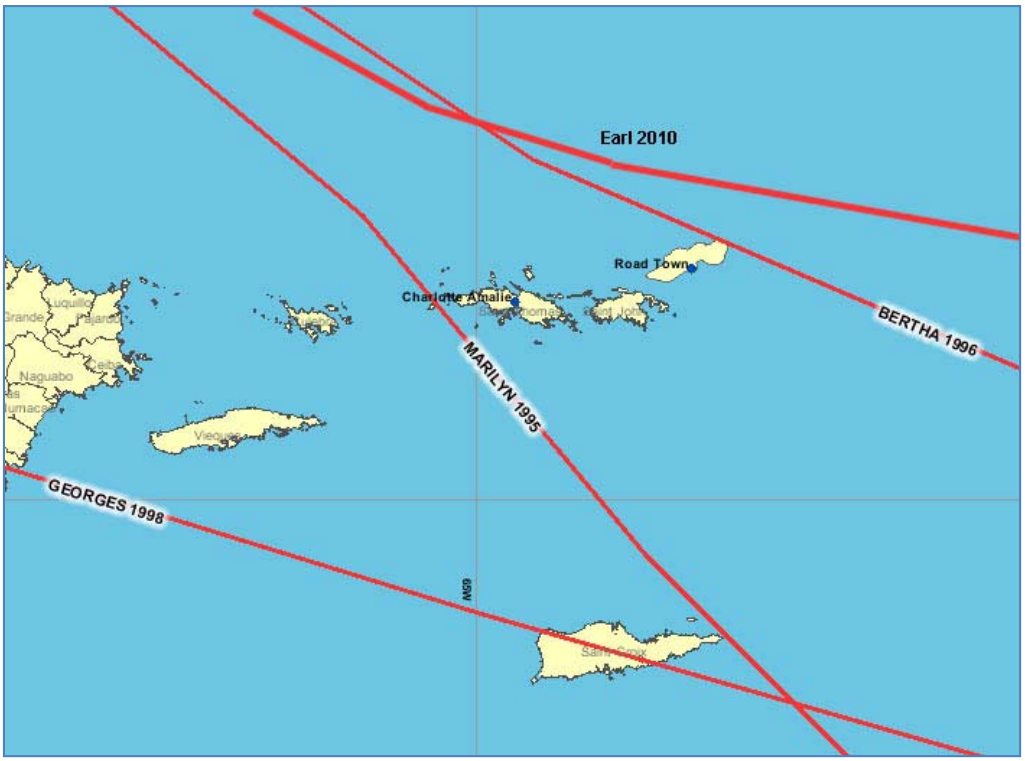

Figure 17. USVI Major Hurricane Tracks. Felton (2014).

In terms of practical experience with wind turbines and hurricanes, Jamaica offers some evidence of survivability. In a 2011 presentation, the project manager for the Wigton wind farm notes that the Wigton 1 project survived Hurricanes Ivan and Dean (Class V and IV, respectively) with minimal incurred damage: $640,000 and $106,000, respectively. The longest recovery time appeared to relate to transmission lines.[38] It should be noted that the turbines involved were of the stall-regulated type, which tends to be higher than for turbines of the pitch-regulated (active control) type.[39]In general, concern over the survivability of wind turbines in hurricanes appears to be decreasing.[40]

In addition to considerations of matching wind turbine class to wind regime (a choice influenced by turbulence as well as by wind speeds), management of the risk appears to be related to a high degree to the ability to maintain control of the wind turbines throughout the storm event. Jargstorf (2010) says that the biggest problem a wind turbine faces in a major storm is the lack of electricity to control its orientation to the wind (azimuth control) and the pitch of the blades. Vestas (and presumably other manufacturers) offers a backup power package that ensures that each turbine has its own power supply even if the grid connection goes down, thus allowing full control of the turbines. In addition to ensuring controllability throughout the event, the use of foundations with higher safety factors and tubular towers (which can also be specified with higher safety factors) are key considerations as well.

Turbine manufacturer Vergnet offers a 1.0 MW model that is designed so that the rotor can be lowered to ground level in advance of a severe storm. Jargstorf (2010) said that it requires two people three hours to lower the rotor/turbine, suggesting that the availability of staff to carry out this task in advance of a hurricane may not be a given.

Solar

Solar energy, particularly that based on photovoltaic generation, is well established and its cost has been falling dramatically over the past several years. Among other advantages, solar output tends to follow load as it rises and falls. Solar installation is well proven in the Caribbean. For example, 65 MW of PV are installed on Guadeloupe and 59 MW on Martinique. Construction of a two-phase, 64 MW solar park in the Dominican Republic began in 2013.

Solar energy potential is usually indicated in kWh per square meter, and is described in two ways: Direct Radiationand Global Horizontal Irradiation (GHI). In areas where cloud cover is a reasonable expectation, and where flat-plate PV is the more likely technology (vs. concentrating solar technologies), the GHI is a more appropriate figure to use.

[38] Wigton 2011
[39] Jargstorf 2010
[40] Rose et al 2012

Table 2 and the accompanying map[41] in Figure 18indicates the high quality of the solar resource in the U.S. Virgin Islands. As would be expected, solar energy availability is highest during the summer, but the

Table 2. Estimated solar resource for the Virgin Islands (Lat 18°N Long 65°W) kWh/m² per day.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
Horizontal	4.78	5.53	6.30	6.74	6.39	6.75	6.72	6.47	6.04	5.47	4.80	4.62	5.89
Tilted	6.06	6.56	6.90	6.78	6.48	7.08	6.99	6.35	6.40	6.29	5.95	5.99	6.48

Source - NASA Surface Meteorology and Solar Energy

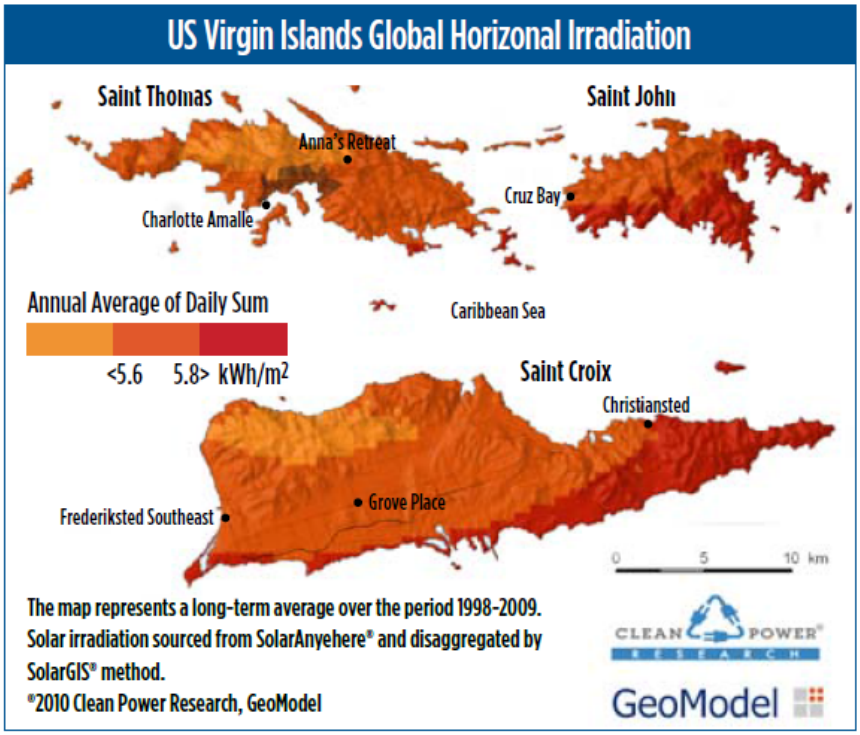

Figure 18. USVI Global Horizontal Irradiation.

resource is excellent year round. NREL has stated that the USVI solar resource is approximately 85% that of the U.S. Desert Southwest.[42]

In terms of total MW potential, this is limited only by the availability of land.In their 2011 analysis of the USVI energy roadmap, NREL assumed the all-islands potential to be limited to 6 to 13 MW due to then-applicable costs, although 18 MW of contracts were awarded in the years since (see below). Solar PV continues to represent a small portion (relative to Total Energy Generation) of USVI energy plan.

In 2013, WAPA issued an RFP for solar project proposals, seeking 10 MW of capacity. Forty five (45) companies expressed initial interest, and 27 companies submitted "very competitive bids." [45] Six (6) companies were shortlisted, including AES Solar, BeSmart Energy Capital, Lanco, SunEdison, SunPower Corp, and Toshiba. 18 MW worth of PPA's (10.5 MW for St. Croix and 8.3 MW for St. Thomas), were

[41] Clean Power Research 2010
[42] NREL 2011a
[45] WAPA 2013b

offered to three parties: Lanco, SunEdison, and Toshiba. The first two contracts were dissolved due to site availability issues, and the Lanco contract was re-assigned to a firm called Main Street Power. The Toshiba project was later acquired by NRG.

A new RFP was issued in December 2013, for 9 MW of PV (3 MW on St. Thomas and 6 MW on St. Croix). Six firms submitted bids for projects on St. Thomas, and eight firms submitted bids for St. Croix. Firms have been shortlisted, but a vendor has not been selected as of this writing.

In terms of pricing, the Lanco contract was to begin at $.1725/kWh, escalating at 3% annually, resulting in a levelized price of $.221 over 20 years. The SunEdison price was fixed, ranging from $.14223 to $.245. The Toshiba price begins at $.155, escalating at 1.5% annually, for a 20 year levelized price of $.1716/kWh.

Expected capacity factors for the St. Croix site PV contracts awarded in 2013 ranged from 20-25% for the St. Croix sites; the St. Thomas projects were projected at 20%.[46]The best options for solar PV in the USVI are fixed tilt and single-axis tracking. While the cost is higher, single-axis tracking offers substantially greater output. A Barbados-related study forecast a 22% greater capture of GHI than fixed-tilt.[47] For this report's analysis, we assumed the use of single-axis tracking.

Solar PV Cost

As noted earlier, costs for PV have been dropping significantly as shown inFigure 19.[48]The California Energy Commission recently estimated that between 2014 and 2024, instant costs for single-axis tracking PV would fall by between 4% and 44% for installations at the 20 MW scale.[49]This is a more optimistic expectation than what is suggested by the E3[48] graph.

Recent cost figures for single-axis tracking PV range from $3,000-$4,000/kW (AC output).[45] For analysis purposes looking forward, we used a figure of $2,800/kW. O&M would be $25/kW-yr. These figures match another set of projections

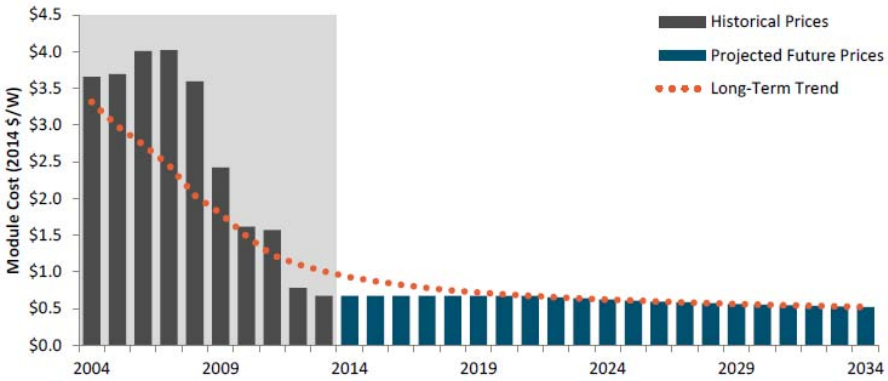

Figure 19. Historic and projected solar PV module prices based on observed learning curve.

[46] WAPA 2013c
[47] Castalia 2010
[48] E3 2014
[49] CEC 2014

for crystalline single-axis tracker costs at $2,794/kWac in 2015 and $2,224/kWac in 2020.[50]These figures are dramatically lower than what was used in NREL's 2011 "Road Map" analysis ($6,000/kW for utility-scale PV). Energy prices for large-scale PV projects in the southwestern U.S. are now reportedly as low as 8 cents/kWh.

Figure 20is from Lazard's most recent (September 2014) assessment of levelized costs for renewable energy.[51] The present range is from $72 to $86/MWh.

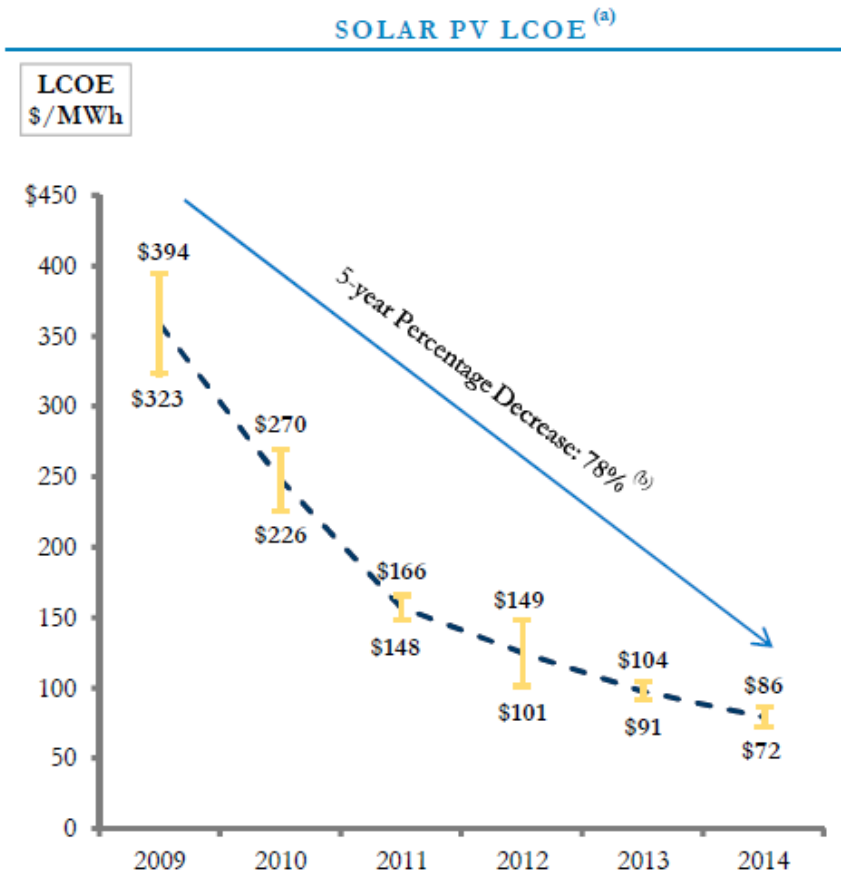

Figure 20. Solar PV LCOE ($/MWh) over time.

Siting

With costs having fallen dramatically, the chief limiting factor to PV development in the USVI now appears to be land area and the capacity of the system to integrate PV output.

Taking advantage of the flexibility in siting, it makes sense to place solar installations as close to load as possible. In St. Thomas and St. Croix, however, the availability of land may be a greater factor. A number of distributed sites at scales of 3-5 MW each may be viable, and this would help reduce the effect of

[50] NPCC 2013
[51] Lazard 2014

cloud-driven intermittency as well as reducing line loss. Solar installations of this size require 5-8 acres per MW, so each site would require at least 15 acres.

The availability of certain sizable, flat, and well-exposed properties could present an attractive alternative to distribute sites. On St. Croix, the HOVENSA refinery site may present such an opportunity. It is described below.

Use of the HOVENSA Site (St. Croix) for a Large PV Project

In 2012 it was announced that the HOVENSA oil refinery on St. Croix's southern coast would close. The refinery, in operation for 45 years, employed 2,500 people. Closure has had a major economic impact. The HOVENSA site occupies 2,000 acres, with additional government-owned land adjacent. An external consultant, Duff and Phelps, prepared a study of the "Highest and Best Use" of the refinery for the USVI government.[52]Their conclusion was that continued operation as a refinery would be the optimal outcome.

Figure 21. Potential Solar PV Site (HOVENSA).

The Duff & Phelps report noted that the site could be a good location for renewable energy projects. It noted that the site gets above average solar irradiation compared with the rest of St. Croix, and that it includes "some of the flattest spans of land in the entire USVI." It is also, of course, zoned for industrial use (I-1).

A detailed analysis of the full site has not been undertaken. However, if only 25% of the site (500 acres) were suitable for solar PV, it could accommodate as much as 62.5 MW of capacity could be installed at the conservative figure of 8 acres/MW. The only downside would be the increased intermittency risk of

[52] Duff & Phelps 2012

concentrating the island's PV production in one location, but this may be compensated for by the balancing effect of the remainder of the portfolio, along with the use of energy storage.

Use of the HONVENSA site for PV could dovetail well with use for onshore wind.

Biomass

Biomass generation involves the combustion of plant matter, agricultural residues, or biogas. The two primary forms of combustion involve either direct-firing or gasification, with the former being more common. Biomass is a well-established form of renewable energy generation. It is not as carbon-neutral as wind or PV, as emissions of greenhouse gases are significant. It does, however, provide a baseload source of generation.

Biomass potential is largely determined by the availability of fuel. NREL's 2011 analysis cited Chakroff (2010)'s estimate that 8.8 tons of biomass could be sustainably harvested per acre per year in non-forested areas. Using land figures for St. Croix, it was estimated that if 10% of land area could be used for the development of biomass, there would be the potential for a 1-2 MW plant on St. Croix. However, the USVI Road Map suggested a potential of 3-5 MW on St. Croix.

Biocrop potential map for St. Croix. *Illustration from* U.S. Virgin Islands Forest Resources Assessment and Strategies, *June 2010, Marilyn Chakroff, Forestry Division, VI Department of Agriculture, Kingshill, VI.*

Figure 22. Biocrop potential for St. Croix.

St. Thomas also has significant land that may be suitable for biomass cultivation, although at a smaller scale than what is available on St. Croix. We've thus used a smaller figure for biomass' role in a St. Thomas renewable energy portfolio.

Capital costs were estimated at $8,200/kW, based on EIA figures for mainland U.S. projects.

In the time since that NREL analysis, Tibbar Energy began developing a 7 MW biogas project on St. Croix that will use fast-growing Giant King Grass as its feedstock. The supply field will occupy an area of 1,000

acres.[53] The project itself will be sited on a parcel west of the Anguilla landfill and owned by the Water and Power Authority, who provided a $15 million loan for the project and awarded it a 25-year power purchase agreement for 7 MW of output. The reported price is $.245 for the first five years, $.24 for years 6-20, and $.23 for the last five years. There will be an option to extend the contract by five years.[54]

Commencement of operation is expected in 2015.There are actually 4 x 3 MW biogas generators, but parasitic load will limit output to 8.5 MW.[55] Capital cost figures for this project are not readily available, but the 2013 Tibbar presentation document states that $75 million will be spent on the project during the next several years. This suggests that the per/kW cost of the project may be upwards of $9,000/kW.

One potential challenge that the project may face is the recent bankruptcy of the European firm that is to supply the biogas equipment.[56] As of this writing, this development has not been reported to have affected the schedule for the Tibbar project.

Waste-to-Energy

Waste-to-Energy (WTE) is a term that includes a range of ways of using solid waste for energy production. WTE is now well-established worldwide. In the US alone, which is among the smaller active markets, there are 84 WTE facilities in operation producing 2,769 megawatt-hours of baseload electricity annually.[57]Varieties of WTE technologies include incinerators, digesters, and land fill extractors.

WTE has attracted interest across the Caribbean region. In Barbados, a 30-35 MW project was recently announced. The plant, expected to consume 650 tons of waste per day and provide for 25% of Barbados' electric energy needs, would go online in 2017. Expected cost is $240 million.[58]

Among the negative aspects of WTE is the production of emissions. A newer technology called Plasma Gasification, which is the technology intended for use in Barbados, has the potential to significantly reduce such waste products. Although, the price of this technology is decreasing, there is currently no commercially installed system in the United States and presents a risk to the USVI.

WTE has been considered for the USVI since at least 1994, when a potential of 1-2 MW per island was suggested by ORNL.[59] In 2010, Alpine Energy Group was awarded contracts for two WTE plants as a result of WAPA's 2007 RFP. These were to include a 33 MW plant on St. Thomas and a 16 MW project on St. Croix. The technology was to have used a mixture of pelletized refuse-derived fuel and petroleum coke, with fluidized bed steam generators. Under the agreement, Alpine was to have been required to accept up to 73,000 tons per day of acceptable waste generated on each island. WAPA was to have paid Alpine for solid waste management, and Alpine would be responsible for ash disposal.

[53] Tibbar 2014
[54] St. Thomas Source 2014
[55] Tibbar 2013
[56] ENDS 2014
[57] ERC 2014
[58] Barbados 2014b
[59] ORNL 1994

The WTE energy price for the Bovoni site was $.14 peak and $.13 off-peak, and for the St. Croix site it was $.15, subject to annual escalation and periodic adjustments.[60] It should be noted that these figures appear to reflect a subsidy in the form of the waste management fees ($91/ton).[53]

The projects raised public opposition, which WAPA described as baseless.[61]WAPA's executive director, Hugo Hodge, reported in 2013 that the initial failure was due both to the opposition of the use of petroleum coke in the projects and to Alpine's inability to obtain authorization from the legislature to lease government lands.[62]In 2011, the contract had been modified to include just the St. Croix project and eliminate the use of petroleum coke. However, Alpine was unable to obtain a government lease on the land in St. Croix, either. The contract was subsequently cancelled. WAPA's Energy Production Action Plan states that the 16 MW project "failed to generate sufficient public support."[63]In 2012, a WAPA representative said that the cancellation "leaves a big hole in our plan to achieve 60% by 2025."[64] Waste-to-Energy was to have met 1/3 of the renewable energy goal.

In 2011, NREL had produced a waste-to-energy evaluation for the USVI.[65] According to this document, 65,000 tons of municipal solid waste per year were collected on St. Thomas (8,600 from St. John and 59,600 from St. Thomas), and 81,500 tons were collected in St. Croix and buried in the Anguilla Landfill. In total, 133,000 tons of waste per year were available for WTE for all islands combined. Using an assumption of .03 MW per ton per day, this would translate into 13 MW of capacity (NREL contrasted this with Alpine's figures, as Alpine had claimed a higher efficiency). The report concluded that the proposed WTE facilities would have economics similar to those in the continental US, offer a lower life-cycle impact on the environment than the status-quo use of landfills, and have the potential to meet all EPA emissions standards.

The USVI Energy Road Map includes a goal of 16.5 MW of WTE.[66] The technology appears to remain a viable potential contributor to the renewable energy portfolio on both St. Thomas and St. Croix. Issues needing resolution include project financing, the need for experienced contractors and suppliers, selection of a proven technology, and the need for a long-term contract for waste. Successfully addressing public concerns would be essential. For purposes of our analysis, we've assumed a 5 MW WTE installation on each island. This could potentially be met by landfill gas alone; the Road Map document cites the EPA as indicating a potential for 3-5 MW of power from landfill methane from the existing landfills, which are under EPA closure orders. A project with a capacity of 0.8 MW appears to have already been constructed at Bovoni, but is reportedly not operating.[67]

The capital cost of a WTE plant can vary widely. We've used a figure of $8,000/kW, which approximates the estimate for the Barbados project and matches industry figures.

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[60] WAPA 2010b
[61] WAPA 2010a
[62] Hodge 2013a
[63] WAPA 2012b
[64] EDIN 2012a
[65] NREL 2011c
[66] EDIN 2011b
[67] EPA 2014

IV. Maintaining Grid Stability and Reliability of Supply

Basics

An electric power grid must maintain a continuous balance between load and supply. If load exceeds supply, the *frequency* of the system can drop, which in turn causes voltage drops, which in turn cause brownouts and blackouts. If supply exceeds load, voltage spikes can occur. Frequency regulation, which occurs at very short time scales, is designed to prevent these problems at a sub-second to seconds time scale.

On a longer time scale (minutes to hours), the system has to maintain the ability to meet fluctuations in demand as well as equipment contingencies. *Load balancing* keeps the system in balance in the seconds-to-minutes time scale. On a longer time scale, certain levels of generation are kept on standby as *spinning reserve* and *supplementary reserve*.

Reserve Requirements

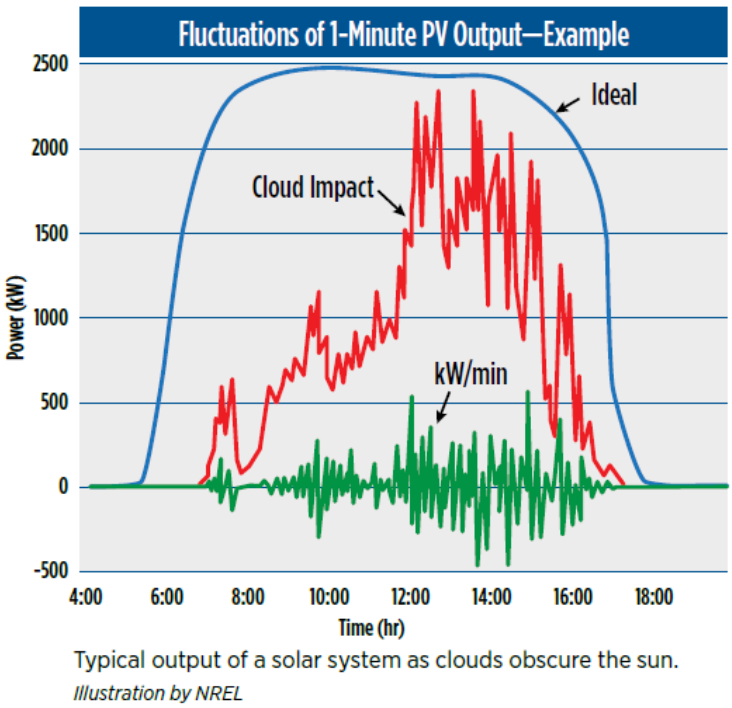
Over the longest time scale, a utility needs to plan its supply additions to ensure it has enough generation on hand to meet major contingencies. The *reserve requirement* is the margin of generation capacity installed above and beyond what the peak load is. Two common standards used for setting this benchmark are 15% of peak load, and an "N-1" contingency (the loss of the largest single generating unit).

Power Quality

Power quality relates to short-time frame dynamics on the system. The main problems encountered at a very local level in relation to renewable resources can include flicker (rapid and small voltage changes caused by variable output of turbine), and harmonics (caused by power electronics). Today's wind turbines can be supplied with equipment that not only compensates for these types of issues, but which can add to grid stability as well. Solar PV Inverters also have the capability of providing reactive power, improving power quality. Battery and capacitor-based Static Synchronous Compensators (SATCOMs) can also be employed for the entire grid.

Challenges Created by High Renewable Energy Penetration

Wind is a variable resource because its output can't be precisely known in advance, although its patterns can be well known through good data collection. Solar energy—solar PV in particular—is not variable, but it does experience intermittency through cloud cover. The charts shown in Figure 23 (based on Virgin Islands data) illustrate this phenomenon for PV:



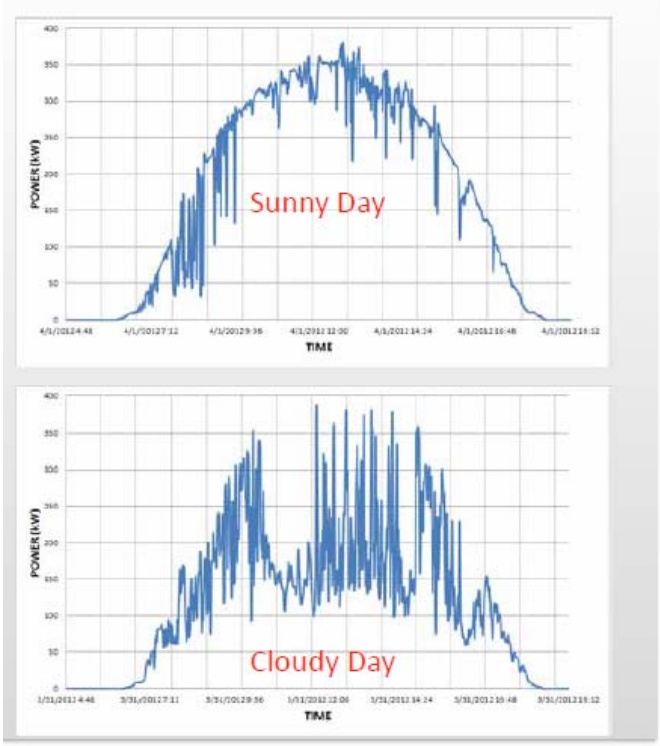


Figure 23. Solar Output Fluctuations.

Changes in wind power output are not as dramatic, but they can be significant. Hutting[68], speaking in the context of Aruba, reports that 35 MW out of 60 MW of wind capacity can drop in 15 minutes. Figure 24 from Hutting, illustrates the variability of wind as compared with the variability of demand.

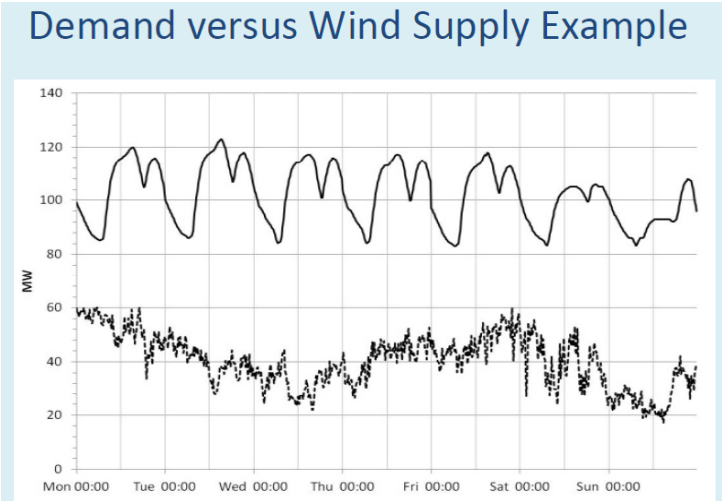


Figure 24. Wind Variability Demand Vs. Supply

Penetration Levels

Conventional standards for the amount of variable/intermittent renewable capacity that a typical utility grid can sustain range from 10% to 30%. This is sometimes called the *penetration level*. WAPA's Energy Production Action Plan states that wind and solar must be limited to no more than 15-25% of demand, and that overcoming this limit needs either storage or a grid connection to another utility.[69]

[68] Hutting(b)
[69] WAPA 2012b

The 30% level has reportedly already been reached in many island contexts, including Corsica, Reunion, and Guadeloupe.[70] The acceptable level of penetration really is very much dependent on the make-up of the resource base. Hutting suggests that there is a "10% penetration myth", citing the fact that many locations have far exceeded this level (e.g., western Denmark at 66%, Spain and Portugal at 43%, Germany at 32%).[71]

Capacity Value

Capacity value is the ability of a generation resource to be available when the system requires it. A conventional generation resource is assumed to have a capacity value of around 90% (taking into account some uncertainty for planned and forced outages). The capacity value of renewable resources varies widely. Geothermal, for example, is a baseload resource that is dispatchable, so it can be controlled to a large degree. It is granted a high capacity value.

At the other extreme, wind is usually granted a low capacity value due to its variability. However, in places where the wind is steadier, capacity value can be higher. Using a common Loss-of-Load Probability (LOLP) methodology, Hutting[72] indicated that a planned 20 MW wind project in Jamaica would have a capacity value of about 7 MW, which is more than 30%. This is significantly higher than figures seen in US interior wind projects, ranging from 0 to 15%. Solar PV is usually granted a higher capacity value, up to 50% or more, as it is highly predictable (albeit subject to intermittency).

For purposes of our analysis, capacity value was not evaluated directly. Rather, we relied on hourly output data for a somewhat more empirical approach. However, good capacity values for wind and PV on or near St. Thomas and St. Croix will only enhance the viability of shifting to a high-renewable base without an inordinate reliance on storage and other backup.

Strategies for Maintaining Grid Stability & Reliability of Supply

Many lessons have been learned about working with significant levels of renewable energy penetration. Among the recommendations[73][74]that would apply to high-renewable systems like what is being proposed by IEI are the following:

1. Operational flexibility. The systems on St. Thomas and St. Croix already have some inherent operational flexibility through the use of a number of smaller units that can be ramped up and down, albeit at a cost penalty. Speed of response will be limited as well. Operational flexibility also applies to the renewable resources themselves. Wind turbines should be equipped with active power and ramp rate limiters, along with frequency control converters.[75][76]

[70] CIREC 2013
[71] Hutting (a)
[72] Hutting KEMA
[73] Brattle 2013
[74] Roesch 2013
[75] Hutting (b)
[76] EDF 2012

2. Fast response. This is particularly true of systems with a large amount of solar PV. Ramp speeds are fastest with storage technologies like batteries and pumped storage, and slowest with conventional fossil units.

3. Increased operating range. The larger the number of generating units, the wider the operating range of each, and the more control is available over each of those, the wider the operating range for the entire system. The operating range of the current system is not bad, because some types of units can be operated at part-load without losing too much efficiency. However, there is an efficiency penalty for part-load operation (see graph below for a diesel-based example[77]). Furthermore, ramping up and down does increase O&M costs, and each unit does have a minimum operating level (~30% for a flexible diesel unit). (It should also be kept in mind that even wind power has the ability to be dispatched in the *down* direction relatively quickly, so it can actually contribute to operating range.)

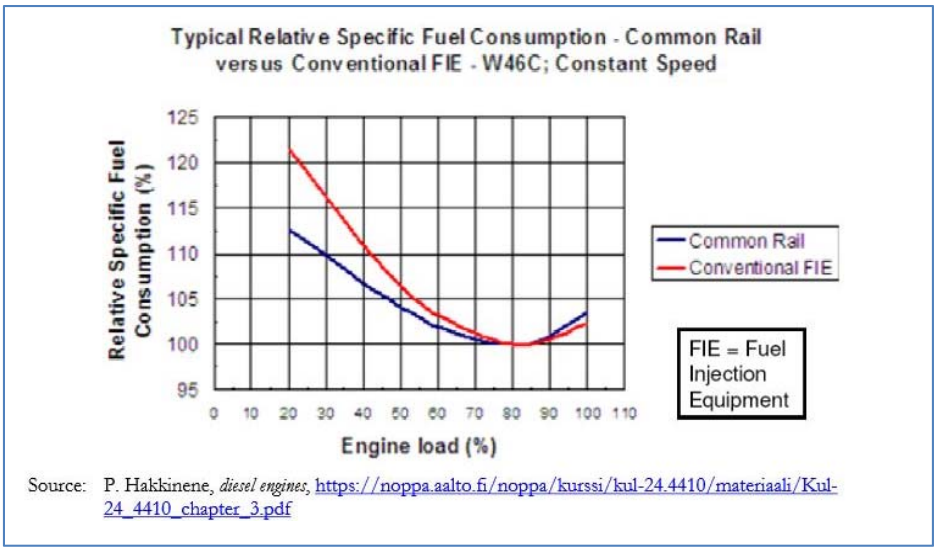


Figure 25. Relative Fuel Consumption of a Wartsila Engine at Different Loads

4. Full system automation. A sophisticated, automated control system would be needed to most efficiently and rapidly coordinate a system high in renewable energy input and using a number of resources for backup and/or storage.

5. Operational forecasting. Wind energy forecasting can be done on short time scales, e.g., by using scanning LIDAR.[78] Prediction will be easier for coastal or offshore sites than with mountain sites.[79]

6. Storage. It is widely acknowledged that energy storage provides a wide range of benefits and services to a utility system. Storage is considered a requirement for the highest penetration systems, and one technology is preferred above others for this kind of situation. Just one example of this is provided here in the context of Aruba, Hutting states: "Demand side management and more flexible operation will raise the use of wind energy from 30 to 35% of total demand...For further expansion of wind energy, a

[77] Castalia 2012
[78] Hutting (b)
[79] EDF 2012

pumped storage system appears to be needed."[80] Energy storage is discussed in greater detail in the next section.

Demand response can be another tool in the portfolio for managing high levels of renewable energy sourcing[63].With demand response, consumers are compensated for allowing system operators to lower or cut demand on short notice. This may be viable for larger industrial customers who have some flexibility in their use of power.

Other High Renewable Transitions in Island Contexts:
El Hierro (Implemented)

El Hierro (Canary Islands) is perhaps the best known example of an island power system being converted to a very high (>50%) renewable energy supply, and certainly a good illustration of the use of pumped storage to achieve this end. El Hierro designed and implemented a system comprised of 11.5 MW of wind and 11.3 MW of pumped storage. Previously completely dependent on diesel generation, the island will now obtain 65% of its energy supply from wind and only 35% from diesel.[81]

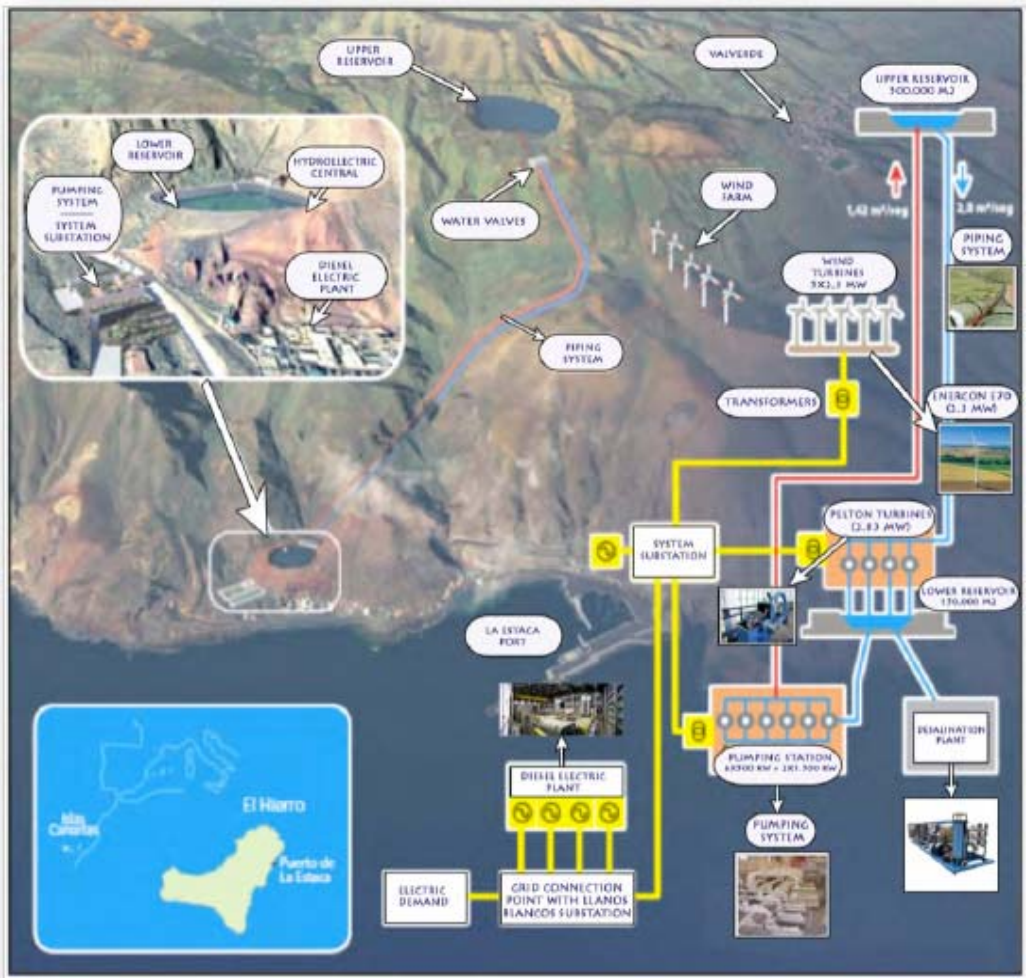


Figure 26. El Hierro, Canary Islands, High RE Penetration System

Recent reports indicate that additional wind turbines are being added to move to a 100% renewable energy supply.

[80] Hutting (b)
[81] El Hierro 2014; Piernavieja 2010; Hallam et al 2012

Other High Renewable Transitions in Island Contexts:
Jamaica (Conceptual)

A conceptual analysis similar in some ways to what is being done here was performed for Jamaica by the Worldwatch Institute, with support by the German government. They considered a range of scenarios of renewable energy penetration and assessed the costs and benefits. Among their findings: "Our technical scenario analysis illustrates that Jamaica can reach a high share of renewable energy through three very different transitioning pathways. The capacity rates at which conventional plants are run decreases progressively with growing renewable energy shares." [82] This was most viable with gradual retirements of existing oil-based units, less so with new gas or coal additions planned for the interim, due to the fear of stranded investments.

The scenario shown below represents the highest renewable energy level transition that was modeled: 94% by 2030. This particular scenario included energy storage backup. The study discovered that without storage, excess generation by solar and wind required a 31% level of curtailment of output of those resources. With storage, curtailment dropped to 19%. It was not clear from the report, however, how much storage was specified, and of what type.

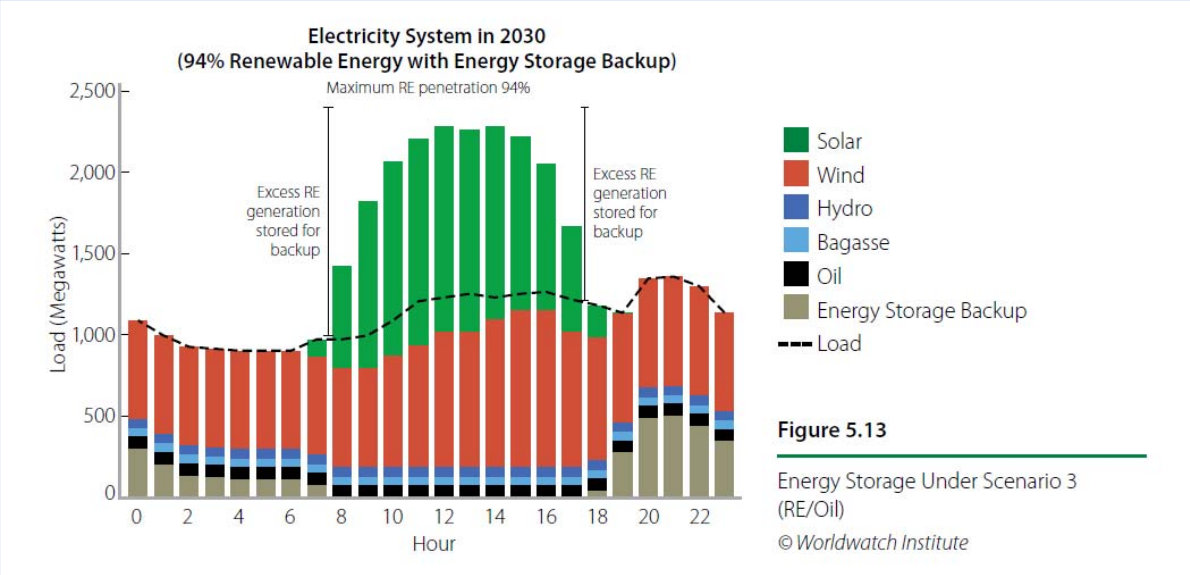


Figure 27. Jamaica High RE Penetration Model Scenario.

In terms of economic benefits, Worldwatch projected a potential *67%* cost reduction between the 2010 baseline and 2030 (Figure 28).

[82] Worldwatch 2013

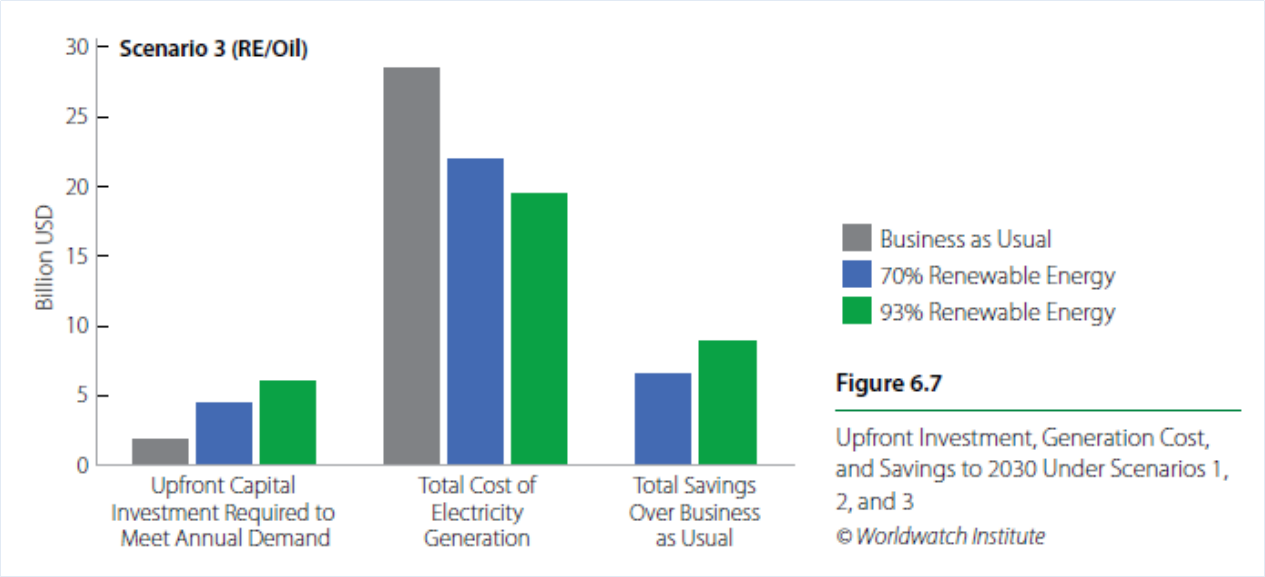


Figure 28. Jamaica Investment, Generation Cost, and Savings for RE Scenarios

V. Energy Storage: Uses and Alternatives

There has been a surge of interest and development in energy storage in recent years, in large part due to the dramatic rise in the use of wind and solar energy. However, it should be noted that large-scale energy storage has been used for many decades in the form of pumped storage hydropower. In 1978, another major storage technology entered the scene, with the 290 MW compressed air energy storage (CAES) plant in Huntorf, Germany. Puerto Rico hosted a major innovation in 1994 when it built a 20 MW battery energy storage system (BESS) at Sabana Llana.[83]

There are a variety of uses for energy storage, and a variety of technologies. The following commonly-seen chart from EPRI (Electric Power Research Institute) illustrates this variety.

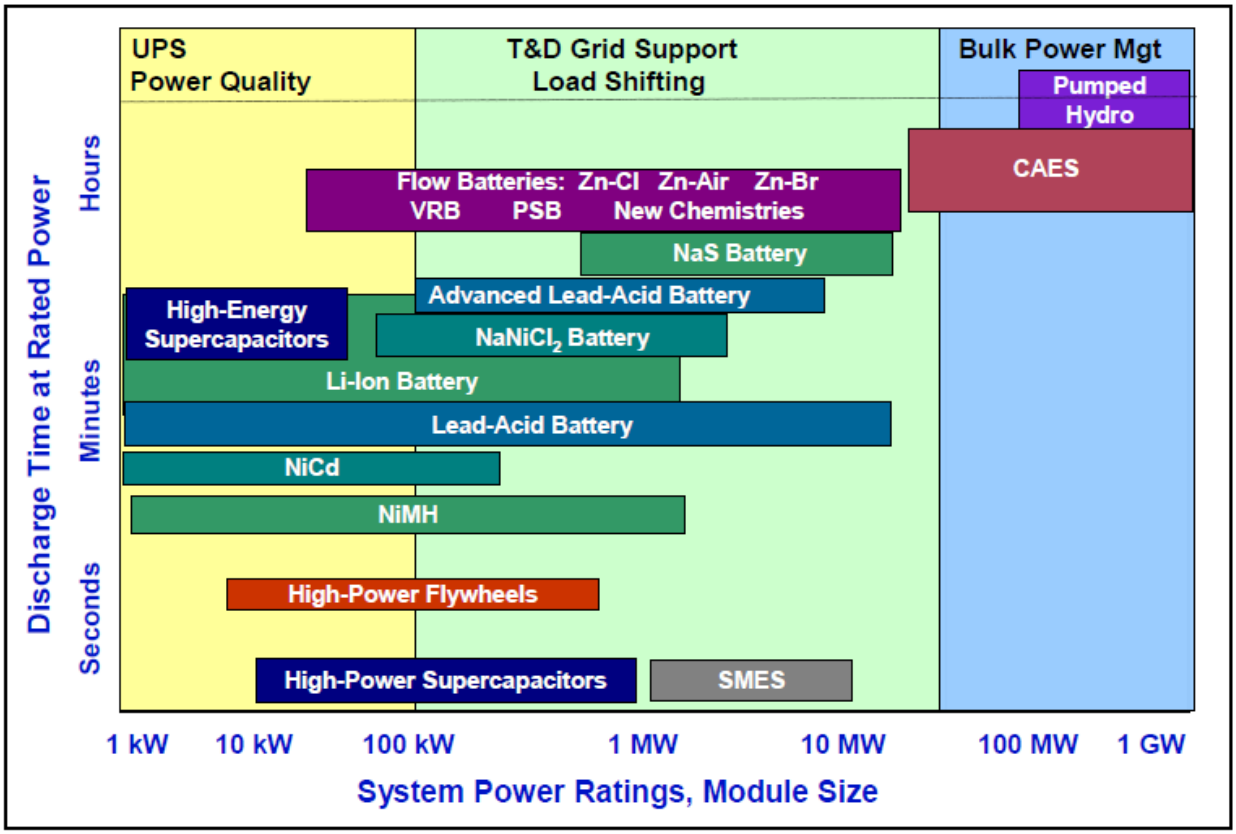


Figure 29. EPRI Energy Storage Comparison Chart

When considering the use of energy storage, which is particularly important for high-renewable settings, it is vital to match the technology to the purpose. This is somewhat complicated by the fact that different technologies may be competing for the same purpose, and by the rapid pace of research, development, demonstration, and implementation being seen today. The chart in Figure 30, (US Department of Energy (2013), illustrates the level of maturity of various energy storage technologies today. Figure 31[84] shows the dominance of Pumped Hydro Storage installations in the United States.

[83] Farber-DeAnda 2005
[84] Electricity Advisory Committee. 2011.

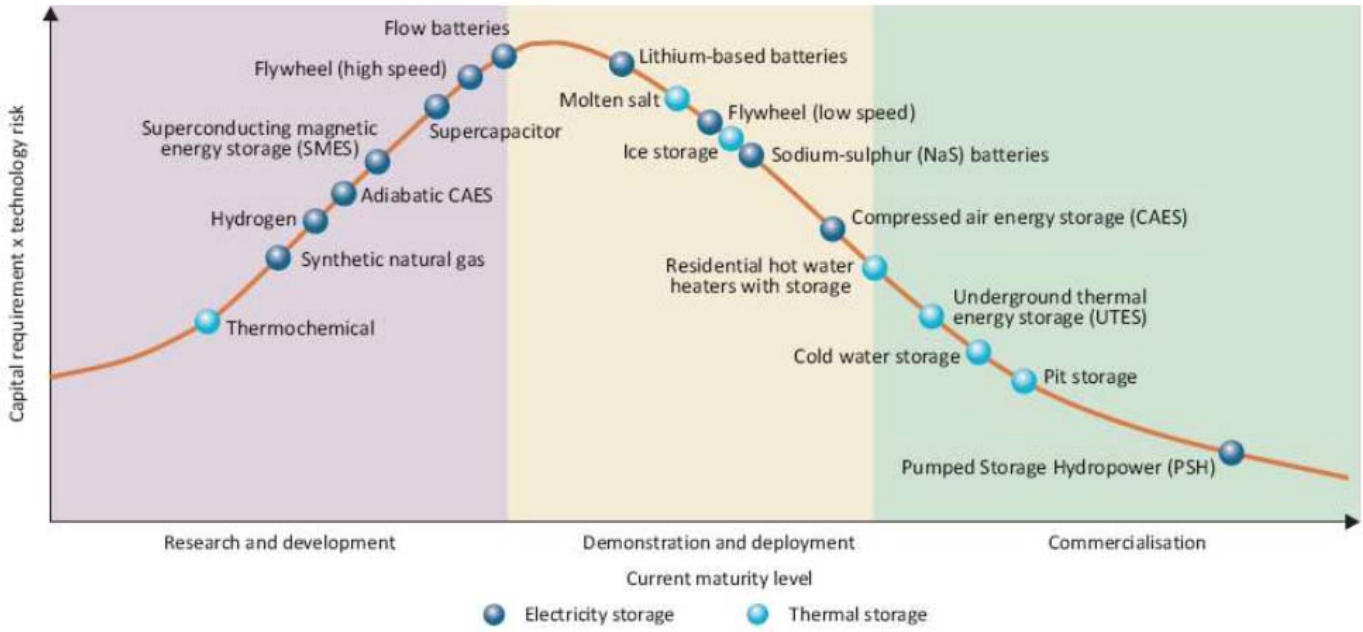


Figure 30. Maturity of Energy Storage Technologies

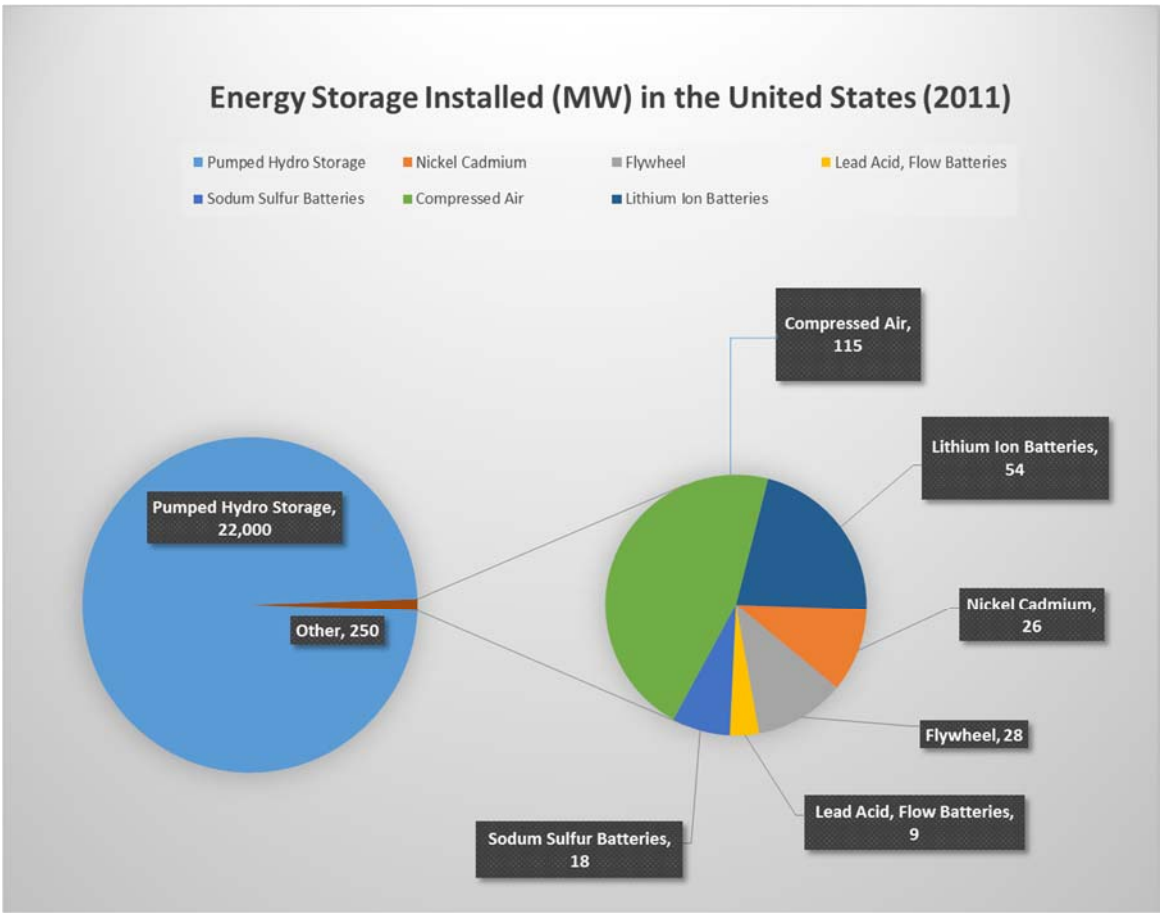


Figure 31. 2011 Energy Storage Capacity (MW) in the U.S. By Technology

Based on the EPRI chart, it is sometimes assumed that pumped storage is only suitable for functions that don't demand fast response. This would be an erroneous assumption. The use of adjustable-speed pump turbines (sometimes called variable speed) has significantly shortened response time, into the millisecond range. This is illustrated in the chart below. Based on long term storage and discharge time, technology maturity, and available sites, PHS is a strong candidate for the best-available multi-hour energy storage technology for the USVI.

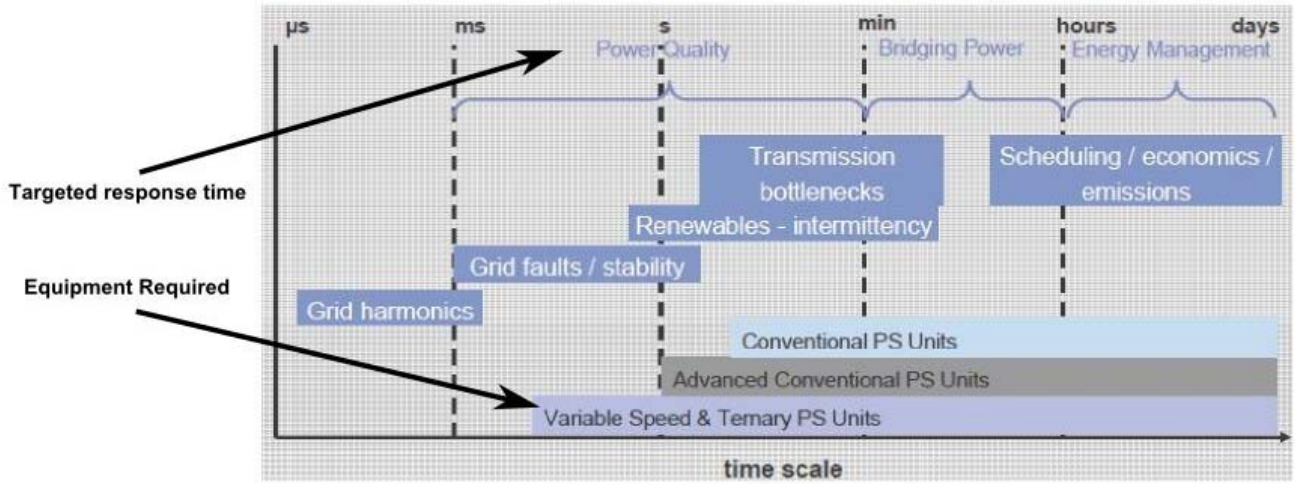


Figure 32. Grid Power Control Issues and PHS Solutions

Pumped Storage Hydropower

Pumped storage hydropower is the best-established and most cost-effective form of large-scale storage in the world today. It has been in use for nearly 100 years, and today there are more than 120 plants in operation worldwide, representing more than 120,000 megawatts of capacity. Projects range in size from the very large (such as the 2,200 MW Bath county project in Virginia) to the small (e.g., the 11.5 MW arrangement in El Hierro). Economies of scale generally favor the large, but pumped storage viability is very dependent on site conditions and market context.

Pumped storage is based on a simple principle: pump from lower to upper reservoir when there is surplus electricity on the grid, and release from upper to lower to generate during hours of need. This is illustrated in the image.

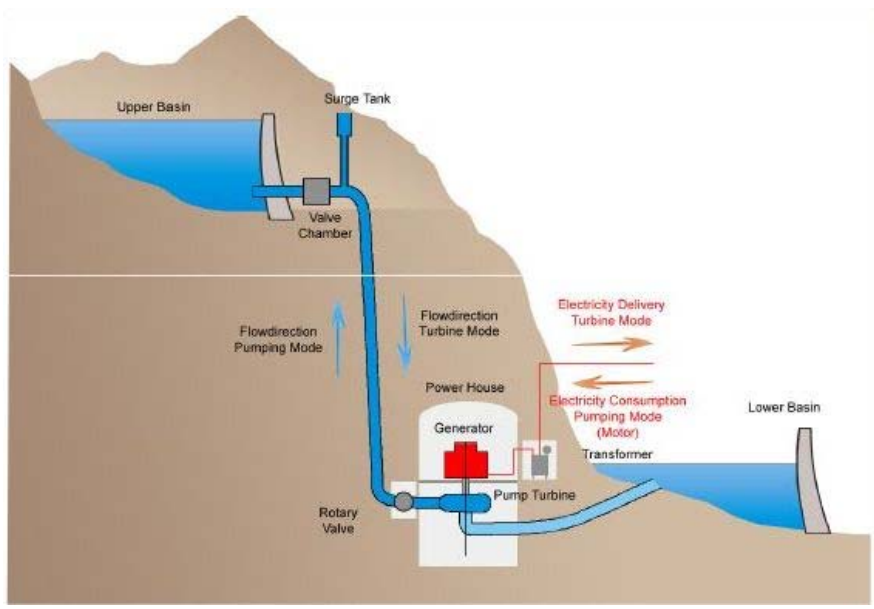


Figure 33. Pumped Hydro Storage Diagram

Reservoirs can be natural or artificial bodies. Historically, most projects used a natural lake or river for at least one of the reservoirs (upper or lower). Some projects took advantage of two existing bodies of water at different elevations. Some projects proposed today are "closed loop" in nature, which means that they don't involve natural waterways at all.

Reservoirs are in most cases connected by an underground tunnel, but in some cases use above-ground conduits. The powerhouse contains the pumping and generating equipment. In the 1950's, the efficiency of combining pump and turbine into a single reversible pump-turbine was discovered, and nearly every pumped storage project built since then uses that approach. There are some that use separate pumps and turbines, which can be advantageous, or even necessary, in certain situations. This is called a *tandem*, or sometimes *ternary*, arrangement.

The round-trip efficiency of historic projects has ranged from 70% to 80%. With the advent of adjustable-speed pump-turbines, which allow for a wider range of operation (particularly in pumping mode), efficiency has generally increased, although it is also affected by the length of conduits.

Pumped storage is very site-specific, with a requirement of relatively high head (vertical drop) over a short distance. The higher the head, the more power is available from less water, reducing the sizing requirements of reservoirs and conduits (which are usually the most expensive components of the plant). Heads for existing projects range from less than 300 feet to more than 4,000 feet. Length-to-head ratio is also important; for higher head sites, this ratio should generally not exceed 10. For lower head sites (<600 feet), a ratio of less than 5 is advised.

In terms of performance characteristics, these vary by project and by design specification. Ramp rates can be very high: the 1,700 MW Dinorwig plant in Wales was designed to go from standby to full power in 12 seconds. Being able to bring the entire generating capacity of a pumped storage plant online in under 60 seconds from standstill is not unusual. When mode changes are involved (e.g., switching from generating to pumping and vice-versa), ramp times are slow; for some fairly modern plants, it can take several minutes to achieve this. The use of separate pumps and turbines can significantly shorten mode-change times, but comes at an added cost.

<u>Pumped Storage Cost</u>

Costs for pumped storage vary widely from project to project, largely because the amount of civil work required varies widely. Cost will also be sensitive to project scale (economy of scale generally in force), and to the amount of storage time desired. Based on Gridflex wide-ranging survey of pumped storage costs and cost estimates, the range may generally be considered between $1,000/kW and $3,000/kW for a project with 10-12 hours of storage. With conventional projects, equipment (the pump-turbines and motor-generators, and ancillary electrical equipment) represents only 15-30% of the cost, with civil works (dams, reservoirs, tunnels, powerhouse construction) representing the balance.

Among the advantages of pumped storage in terms of cost, is its lifetime. To our knowledge, no pumped storage plant has ever been retired. Lifetimes can be assumed to be at least 60 years, and possibly much

longer. Overhauls to the equipment can be expected at the 20 year (motor rewinding) and 30 year (turbine runner replacement) marks.

Pumped Storage in Island Contexts

Due to its proven nature, cost-effectiveness, and versatility, pumped storage appears to be the storage technology of choice for island systems looking at transitioning to high levels of renewable energy. The following are examples.

Implemented

- Okinawa: 30 MW (see discussion in Seawater Pumped Storage)
- El Hierro: 11 MW (see earlier discussion)

Proposed/Under Study

- Guadeloupe: 50 MW / 1 GWh storage / Seawater, intended to permit 50% renewable energy penetration[85]
- Antigua: 15 MW / Seawater, to be paired with wind[86]
- Haiti: 10 MW, proposed to be paired with 10 MW wind, 8.6 MW PV, diesel backup[87]
- Jamaica: Size unknown; Seawater site, high head[88]
- San Miguel (Cape Verde Islands): 20-50 MW (river, seawater options)[89]
- Soduroy (Norway): 2.5 MW generation, 5 MW pumping, to be paired with 10 MW wind[90]
- Ikaria (Greece): Small concept; would allow much higher renewable penetration.[91]

Seawater Pumped Storage

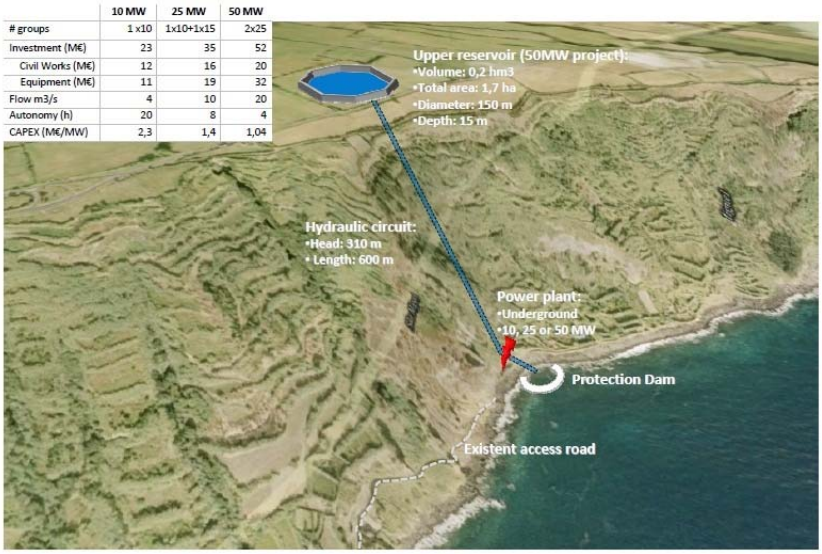
The use of the ocean as a lower reservoir is a possibility in many coastal areas. The chief advantage is that only one reservoir—the forebay—needs to be constructed. There is one seawater pumped storage project in operation in the world: the Yanbaru project in Okinawa (Figure 34). A 30 MW facility, it was completed in 1999. The project required the

Figure 34. Okinawa Japan Pumped Hydro Storage Facility (Saltwater)

[85] ARER 2012, France 2013, EDF 2013
[86] Antigua 2014
[87] Brown & Ward 2014
[88] Jamaica 2013a,b
[89] Pina et al 2008, Marifer 2009
[90] Norconsult 2013
[91] Caralis 2009

development of special stainless steel alloys, along with heavy-duty lining of the reservoir to prevent seawater from infiltrating into the ground. Special measures had to be taken to prevent fouling of conduits by marine life.

Seawater pumped storage is more expensive than freshwater pumped storage. The cost for the Okinawa project was very high—around $8,000/kW—although that might be expected for a relatively small, first-of-its-kind facility with relatively low head (about 300 feet). Martifer Renewables, which has studied new seawater pumped storage proposals, suggests that O&M costs will be roughly 3 times higher for seawater projects.[92]



	10 MW	25 MW	50 MW
# groups	1 x10	1x10+1x15	2x25
Investment (M€)	23	35	52
Civil Works (M€)	12	16	20
Equipment (M€)	11	19	32
Flow m3/s	4	10	20
Autonomy (h)	20	8	4
CAPEX (M€/MW)	2,3	1,4	1,04

Figure 35. Okinawa Japan Pumped Hydro Storage Facility (Saltwater)

Martifer's work has also produced some cost estimates for new seawater pumped storage schemes. Two 40 MW alternatives on Sao Miguel Island (second image) were estimated at about 55 million euros each ($80 million in 2009), or $2,000/kW with 4 hours of storage. A proposed 50 MW project in Guadeloupe, with only 50m of head and a 60 hectare reservoir for 1 GWh of storage (20 hours), was projected to have a cost of 250 million euros, or roughly $6,500/kW[93]. A later reference had a reduced figure of 12 hours of storage and said costs had increased to 340 million Euros, or more than $8,000/kW.[94]

<u>Pumped Storage is likely the best primary energy storage option for the U.S. Virgin Islands</u>

- Pumped storage hydro is the best proven, most cost-effective bulk energy storage technology available today.
- Worldwide operating capacity is more than ~120,000 megawatts and ~120 projects.
- Project lifetimes exceed 60 years.
- Best combination of flexibility, speed, efficiency, storage time, and lifetime among energy storage technologies.
- New pumped storage hydro is very efficient, as high as 83%, depending on the site and technology.
- Supporting high renewable energy penetration requires many hours of storage – no other technology is as suitable for this purpose on St. Thomas and St. Croix.

[92] Martifer 2009
[93] ARER 2012
[94] France 2013

- Both St. Thomas and St. Croix offer several potential pumped storage sites (the results of our preliminary survey are discussed below).

Special Considerations for Smaller-Scale Pumped Storage

Minimizing Underground Construction

Civil works represent the greatest cost element of pumped storage plants. The primary strategy for minimizing construction cost, regardless of the scale of the project, is to use higher head sites with shorter conduit distances, existing reservoirs wherever possible, and natural landforms to minimize dam sizes as shown in Figure 36. Development at a smaller scale (e.g., 20-50 MW) entails economy of scale penalties, so the need to minimize construction costs is even greater in this case. The key difference with the smaller projects will be to avoid underground construction through the use of above ground conduits (vs. tunnels) and the use of shaft powerhouses (vs. caverns).

Figure 36. Bear Swamp PHS Reservoirs. Rowe, MA

Above-Ground Conduits

Larger projects tend to use underground tunnels because at the required headrace and tailrace diameters (usually >10 feet), it is cost-effective to use tunnel boring machines. Tunnels provide a shorter path than above-ground conduits, particularly if powerhouses are underground, and have no surface footprint. The larger project can also absorb the cost of geotechnical site investigations that are necessary before tunneling layouts, lining requirements, can be finalized.

In the case of smaller pumped storage for St. Thomas and St. Croix, none of the above conditions apply. Conduit diameters will be significantly smaller. Powerhouses will not be located deep underground. Tunneling is not out of the question (this to be determined during engineering investigations), and indeed, some shallow tunneling may be needed in some cases to provide the shortest path between reservoirs. However, it is more likely that above-ground conduits will be most economical in most cases.

Shaft Powerhouses

While the majority of pumped storage projects use underground caverns, there are a number of examples of pumped storage projects using shaft powerhouses. As indicated by the name, shaft powerhouses are located in shafts constructed from ground level downward. These include Foyers (Scotland), Avce (Slovenia), Bajina Basta (Serbia), Xixou (China), Jiangsu Shahe (China), Kalayaan (Philippines), Wivenhoe (Australia), and the recently constructed Olivenhain-Hodges project near San Diego. Depths for these powerhouses are as great as 80 meters.

Advantages of shaft powerhouses include lower construction cost and avoidance of the need to construct access tunnels, since ingress and egress are afforded by elevators. Equipment is lowered in through the use of gantry cranes. One disadvantage to the use of a shaft powerhouse is that it places greater distance between the upper reservoir and the turbines, which increases response time.

The deeper the shaft, the more expensive it will be to construct, and the greater the geotechnical complexity to deal with. Depth will be driven by the submergence requirement of the pump-turbines or pumps. This is the need to position the pumps a certain distance below the lowest level of the lower reservoir in order to reduce the risk of cavitation damage. For conventional (single-speed) pump-turbines, a common ratio between maximum head and submergence requirement is .10 to .12. For example, for a maximum head of 1,800 feet, the pump-turbines might have to be 180 feet below the lower reservoir minimum.

In order to avoid this degree of submergence (and underground construction), there are strategies to be considered on both the equipment selection and the civil sides. Adjustable speed pump turbines—which we are likely to need for a number of reasons discussed elsewhere in this section—have a lower submergence requirement than conventional units. Multistage pumps, which may be used in tandem with separate turbines, have significantly lower submergence requirements. An additional consideration for placing a powerhouse above ground or semi-above ground are noise and surface footprint.

Availability of Smaller Scale Reversible Pump-Turbines

All pump-turbines are custom designed for a given project, and there are no engineering obstacles to the design of smaller units. However, two of the leading manufacturers of pump-turbines appear to be preparing to offer new designs for pump-turbines specifically targeting the smaller scales applicable to our case. As indicated at the Hydrovision 2012 conference and through recently published technical papers[95], Andritz has been designing what they refer to as a "standardized," adjustable-speed reversible pump-turbine that can be manufactured at scales as small as 20 MW, and possibly smaller. Their literature refers to a head limit of about 750 feet (probably to increase the number of sites where the units could work), but this would work for many of the candidate sites on St. Thomas and St. Croix.

[95] Krenn et al 2013

Voith recently announced a contract for a 12 MW gen/15 MW pumping, three-stage reversible pump-turbine for the Rellswerk pumped storage project in Austria. The site has a maximum head of 1,700 feet.The multi-stage feature allows shaft depth to be minimized.

Number of Units

The use of more units creates a wider range of operation. However, more units occupy more space on the powerhouse floor, thus necessitating larger powerhouses. There are also bound to be economy of scale penalties for smaller units. Therefore, it has been assumed that a 20 MW project will use 2 units (i.e., 2 x 10 MW). These may be 10 MW reversible pump-turbines, with additional pumping capacity provided by supplemental centrifugal pumps, or separate 2 x 10 MW Francis turbines and 3 x 10 MW centrifugal pumps.

Response Time and Range of Operation

The goal of any bulk energy technology is to offer the fastest possible response rate, ramp rate, and range of operation. There are several ways to maximize these, but as the graph below indicates, only variable (adjustable) speed pump-turbines offer response times in the sub-second range. Alstom and others have cited figures of 150 milliseconds for "step changes" in output for adjustable-speed pump turbines.

In addition to responding at the sub-second range, adjustable-speed pump turbines have a wider range of efficient operation in both generating (down to 25% of nominal) and (more significantly) pumping mode (down to 50% of nominal).

In the case of separate turbines and pumps, we would have wide range of operation in generating mode but probably a reduced range of operation in pumping mode, unless a larger number of smaller pumps were used, which would increase complexity and cost. One recent comparison between adjustable speed and ternary designs suggests that the latter would be significantly slower in response time for purposes of grid frequency support due to its reliance on physical adjustment mechanisms (vs. power electronics for adjustable speed pump-turbines).[96]

[96] Nicolet et al 2014

VI. USVI Pumped Storage Potential

Site Selection

Identification of potential pumped storage sites usually begins with an analysis of physical potential; in other words, the availability of sufficient head (vertical drop) over a short enough distance. This is the primary requisite for a workable site, and appears first in the following set of screening criteria:

- **Head** (vertical drop that determines how much power will be available per unit of water volume; generally speaking, the higher the head, the better)
- **Length of Conduit** (the greater the length, the more expensive and less responsive the system)
- **Length:Head Ratio** (ratio influences engineering feasibility and cost)
- **Civil requirements for reservoir construction** (the size of dams and amount of excavation required to create desired storage volume, which strongly affects cost, is in turn strongly affected by topography and geology)
- **Geology & Seismic Considerations** (includes slope stability, strength of rock for dams)
- **Constructability** (includes access to the site, availability of "laydown" areas for construction, soil and geologic stability, and availability of suitable material for dams and reservoirs)
- **Water** (available water supply for filling the reservoirs and compensating for evaporation loss)
- **Environmental & Land Use Considerations** (impacts of construction and operation on flora and fauna, particularly if existing lakes or rivers or ocean are used; visual impacts; compatibility with existing and planned land uses)
- **Historical & Cultural Considerations**
- **Proximity to Transmission** (the longer the distance to transmission of sufficient voltage and capacity, the higher the cost of interconnection and challenge of routing the generation interconnection line)
- **Location in Grid** (location affects interconnection feasibility and reliability benefits)

Methodology Used in this Study

For purposes of this Pre-Feasibility Report, we applied only the first several screening criteria—more specifically, a topographic screening for sites that could offer the requisite head over reasonable distance while affording at least 240 MWh of storage potential, or 20 MW with 12 hours of storage. This amount of desired storage was indicated by the portfolio optimization analysis, which is described below.

To provide that level of storage capacity for the given amount of head, we looked for sites amenable to reservoir construction with the smallest possible dams and reservoirs. In some cases, natural topography would allow for a dam in a valley, ravine, or depression. In such cases, we sought to limit dam height to no more than 100 feet (in most cases significantly lower). For cut-and-fill artificial reservoirs on relatively flat ridgelines or a plateau, a ring embankment height limit of 40 feet was used, which can be reduced with more excavation. The actual heights of dams and ring embankments will need to be determined through engineering studies.

After screening a larger number of candidates, three sites on St. Thomas and two sites on St. Croix were selected for further consideration. Each site has several alternative possible configurations. The set includes the following features:

- All sites are closed loop (two new reservoirs involved).
- Heads range from 550 to 1,500 feet.
- Length:Head ratios range from 3.0 to 8.0.
- Sites require from 200 to 400 acre-feet of water for initial fill (over 1-2 year period).

No seawater pumped storage options were selected at this point. Details on the candidate sites can be found in Confidential Appendix A.

The next level of analysis for the pumped storage candidate sites will involve more detailed screening for environmental and land use compatibility showstoppers. Following this, reconnaissance-level engineering and pre-feasibility engineering reviews would follow. Each subsequent level of engineering review refines the working design concept and the cost estimate.

Once a site is selected to take forward into development, it may take two years to complete engineering, environmental, and other tasks, and probably two years for construction.

Water sourcing is an issue that should be addressed early on. While 200 to 400 acre-feet is not a large amount of water in a larger system, it is not an insignificant volume on St. Thomas and St. Croix.

Pumped Storage Cost

As mentioned earlier, pumped storage capital cost is highly dependent on the unique circumstances of the project and site. The "average" range for larger projects is between $1,500 and $3,000/kW, with storage times rarely as high as the 20 hours specified here. Given the smaller nature of the projects in this case, the location, and the characteristics of the sites reviewed, we are using an overnight cost figure of $3,500/kW. Pumped storage O&M costs were assumed to be $20/kW-yr.

VII. Renewable Supply Modeling

Methodology

In order to gain a better understanding of what a high-renewable portfolio coupled with storage might do to meet the electric power needs of the U.S. Virgin Islands, we used a proprietary set of worksheets developed by Gridflex Energy specifically designed to model this combination. The model uses a full year's worth of hourly wind or other renewable power output figures, input parameters for storage capabilities, efficiency, minimum pumping and generating levels, and other factors, and firm output (or firm load) parameters that need to be met.

Outputs show the amount of renewable energy that was cycled through storage, the amount of energy that might exceed storage levels (and thus be subject to curtailment), and the degree to which the combination meets (or falls short of) the contract or load requirements. The resulting optimized proportions of various resources are then fed into pro formas for each resource type, where energy costs are calculated.

<u>Selection of Portfolio</u>

The selection of energy resources to include in the portfolio that was modeled was driven by the following:

- Realistic & conservative availability of the resource
- Contribution of the resource to meeting load & reliability needs
- Cost of the resource
- Best fit of the resource within the larger mix, as determined by preliminary modeling

Element 1: Wind: *Largest single element by new capacity for St. Thomas; 2nd largest for St. Croix*

- In the case of St. Thomas, assumed majority off-shore, minority on-shore.

Element 2: Solar PV: *Largest element by new capacity for St. Croix; 2nd largest for St. Thomas*

- On St. Croix, concentrated in the area of the HOVENSA plant; on St. Thomas, more distributed across load areas.

Element 3: Biomass: *Baseload contributor.*

- Assumed for study purposes to be limited to 10 MW on St. Croix; 4 MW is assumed for St. Thomas.

Element 4: Waste-to-Energy: *Baseload contributor.*

- 5 MW ceiling assumed for each of St. Thomas and St. Croix.

Element 5: Conventional: *Level of conventional retained (assumed LPG after conversion) based on magnitude of need for back-up power and energy.*

- Following integration of wind, solar, biomass, &WTE inputs, the amount of conventional generation retained was driven by the resulting shortfall in ability to meet load. It was assumed that retained units would continue to operate with upgrades.

Element 6: Pumped Storage: *MW and MWh levels driven by modeled need.*

- Generation and pumping capacities can be adjusted separately under the assumption that even if reversible pump-turbines are used, additional pumping capacity can be added. It should be kept in mind, however, that conduits would have to be sized for maximum pumping flow, rather than maximum generating flow.
- Storage time in MWh was driven by need for reducing curtailment while being able to meet firm demand, within limits of cost viability (i.e., one can build 100 hours of storage, but it would be much more expensive to do so, even with a high-head site).
- Average round-trip efficiency of 80% was used.

Element 7: Battery:*Moderate amount for regulation services, support to other elements in the portfolio.*

- It was assumed that with pumped storage providing the greatest flexible generation and storage contribution, battery capacity in MW could be limited to 5 MW (about 10% of peak load in STX and 8% in STT) and a short duration of storage (15 to 60 minutes).
- Battery capacity was not counted toward portfolio load-serving capacity, but should be in future, more refined modeling.
- Battery utilization rates and losses were not modeled.

Energy Inputs

<u>Wind Output Calculations</u>

In order to model and modify the contribution of wind energy to the system, we used recent hourly wind output projections from the region. The best data record available to us was the 2013 hourly record from Bovoni Point, St. Thomas, USVI. This data set was released earlier this year by NREL, who has been updating the results. Note. Longford (St. Croix) data is available and shall be used in the Feasibility Study.

The Bovoni Point data was recorded at a level of 55 meters, which we scaled up to 85 meters (the minimum hub height for today's larger turbines). We used a very modest wind shear factor to account for the increase in wind velocity over that height increase, under the assumption that a large portion of the wind capacity would be offshore.

Following revision to the wind speed data, we applied the hourly windspeed data to a calculator that can refer to the power curves for any number of wind turbines in the database. We selected the Vestas V112 3.0, which is a 112 meter turbine that is available for both onshore and offshore use. This turbine is available with Class II specifications, which represents medium-turbulence and wind load, but offers a high capacity factor in a moderate wind environment. Higher capacity factor is a desired value for wind

projects designed to be paired with storage for meeting firm load needs.[97]The power curve table was derived from a 2011 Vestas technical document.[98]

Air density has a significant effect on wind turbine output, and it is driven by elevation, temperature, and humidity. Normally, a sea-level wind project would be assumed to have the highest air density. However, we adjusted the density downward somewhat (from 1.225 kg/m^3 to 1.175 m^3) to account for higher humidity in the region. [99]

A 12% loss factor was applied (factors in wake losses, planned & forced outage, electrical losses) to the resulting power output figures. The result, using this particular turbine, was a net annual capacity factor of 38.4%, which is an excellent energy output level for wind projects. This number matches the most recent figures seen from NREL, according to which net capacity factors based on the Vestas V100-1.8 may exceed 40% at Bovoni Point.

It should be kept in mind that the actual turbine selected for use may be different, and different turbines may be selected for offshore vs. onshore use. Micrositing will determine actual loss factors to apply. Also very important will be the difference between measurements taken at a single tower versus the output of a number of turbines spread out across a wider area, particularly if some of the capacity is onshore and some offshore.

Solar PV Output Calculations

In order to calculate solar PV contribution to the energy mix, we relied on NASA's RETScreen database and calculator a nearby location (Martinique). Single-axis tracking offered a significant energy output advantage over fixed tilt, so this option was selected. The resulting hourly figures were entered into the worksheet. Net annual capacity factor, based on AC capacity, was 25.8%. In order to err on the conservative side, we reduced this by 5%.

Biomass &Waste-to-Energy

For St. Thomas, waste-to-energy was entered at 5 MW of nameplate capacity; 4 MW of biomass was allocated. For St. Croix, waste-to-energy and biomass were set at 5 MW and 10 MW, respectively, respectively (for reasons described in Portfolio Selection). 90% annual capacity factors were assumed for these baseload resources.

Other Model Assumptions

- For simplicity's sake, modeling was based on meeting the current peak loads, whose growth is assumed to be moderated both by economic conditions and energy efficiency gains.For distant future projections, some adjustment in supply-side ratios would need to be made to factor in resource-specific limits (e.g., one can't assume that solar capacity will double just because the load doubles).

[97] Succar et al 2012
[98] Vestas 2011b
[99] Chadee & Clarke 2013

- The hourly load profile was derived based on hourly generation figures for 2013-2014 as provided by WAPA.
- The default supply scenario was based on the USVI Road Map, along with the estimated 30% reduction in fuel cost due to conversion to propane. Figures were also adjusted to fit more recent cost figures for solar and wind, so that the comparison between the "Road Map" scenario and IEI's High-Renewable scenario would be more "apples to apples" in nature.
- The cost of the High-Renewable supply compared with the assumed Road Map scenario was calculated after technical integration (of renewable elements and storage) was optimized.

Modeling the Baseline Scenario

The Baseline Scenario is based on the USVI Road Map as initially developed in 2011. Some of the assumptions were modified based on actual experience and more recent data, so that the comparison between the Baseline Scenario and the IEI High-Renewable scenario would be more "apples to apples." It should be noted that our term "Baseline Scenario" is not synonymous with the term "Base Case" as used in the Road Map documents, although it is based in part on that base case, which was the strategy selected for pursuit in the USVI. By the same token, the term "IEI High-Renewable" should not be confused with the high-renewable case used in the Road Map documents.

Assumptions[100]

- The same load data used for the High-Renewable models was assumed for the Baseline scenario.
- Full LPG (propane) conversion was assumed; no conversion to LNG was assumed (based on the issues discussed in the Conversion section above).
- No new conventional was added; the assumption was that existing units would continue to be operated.
- A 30% reduction in fuel cost over 2013 figures was credited to the Baseline scenario (based on WAPA estimates, as discussed earlier in this report).
- The renewable portfolio under the Baseline scenario consisted of the following:
    - For St. Thomas, 12 MW of wind, 6 MW of PV solar, and 5 MW of WTE.
    - For St. Croix, 10 MW of wind, 6 MW of PV solar, 5 MW of WTE, and 7 MW of biomass.

The economic results of this combination, as modeled by IEI, is described below, along with the economic results for the High-Renewable models.

[100] USVI Road Map Analysis Assumptions

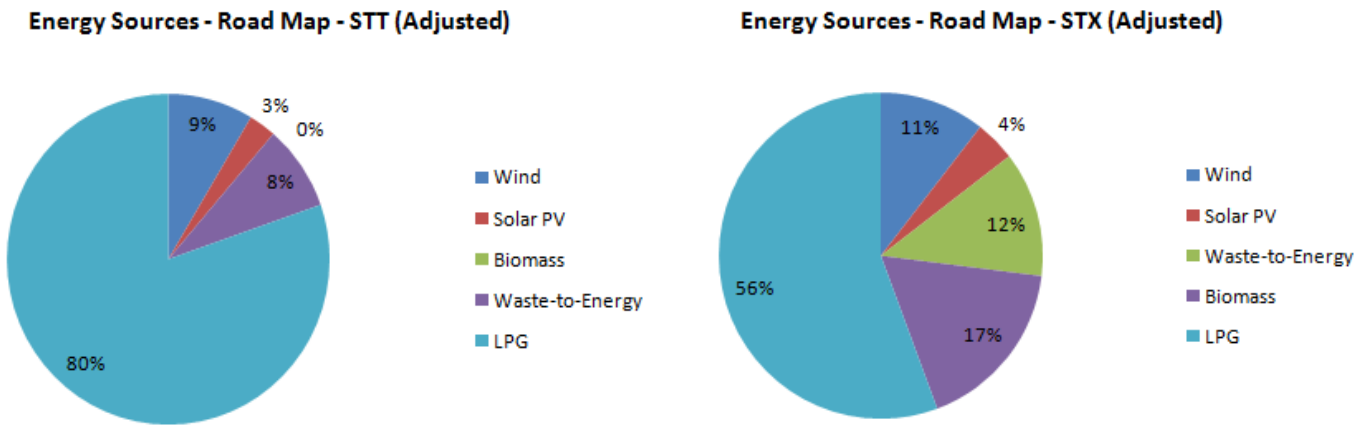


Figure 37. USVI Energy Sources - Road Map

Technical Results: High-Renewable Models for St. Thomas/St. John and St. Croix

(1) Technical Results: St. Thomas/St. John

Renewable Supply Base – Preliminary Portfolio Optimization – St. Thomas Peak Load:74 MW Annual Energy Need: 471,437 MWh	
Wind	75 MW (20 MW onshore, 55 MW offshore)
Solar PV	60 MW (AC)
Biomass	4 MW
Waste-to-Energy	5 MW
Conventional Fossil	59 MW (min) capacity retained, 78,467 MWh generated (15% capacity factor)
Pumped Storage	20 MW generating / 30 MW pump / 12 hours storage (240 MWh)
Battery	5 MW generating and charging, <1 hour storage
Curtailment	13% (applied only to wind, pending further optimization)

11% of energy output was cycled through storage. With 20% losses, this means that only 2% of energy was lost through storage.

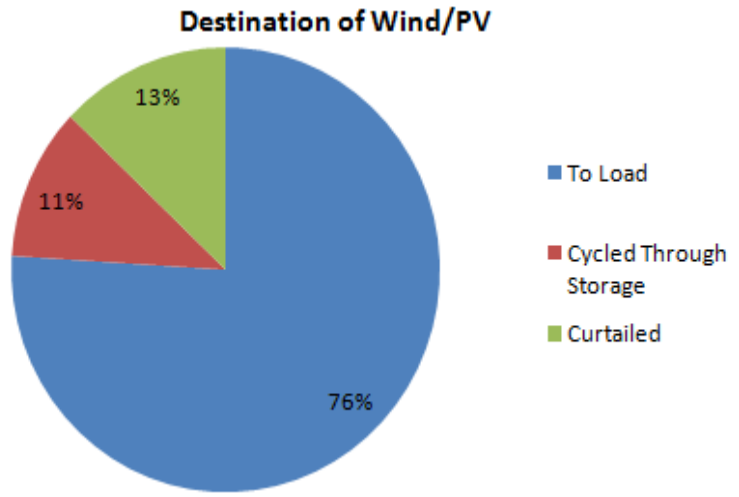


Figure 38. Wind / PV Destination – St. Thomas

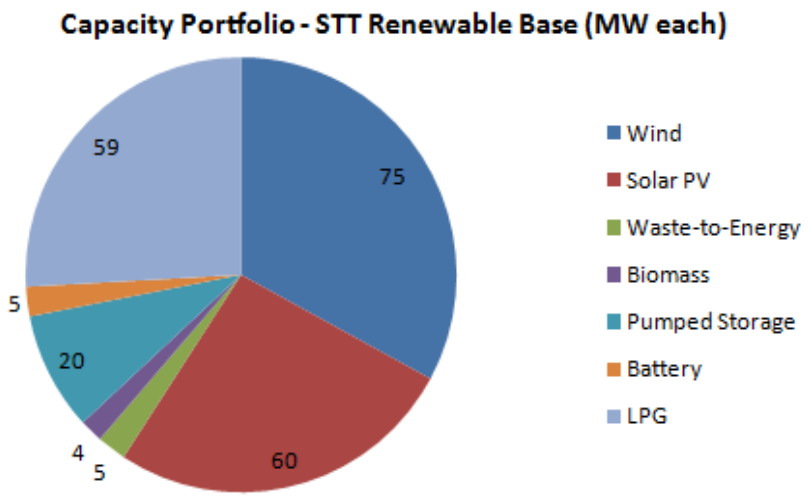


Figure 39. Capacity Portfolio - St. Thomas RE Base

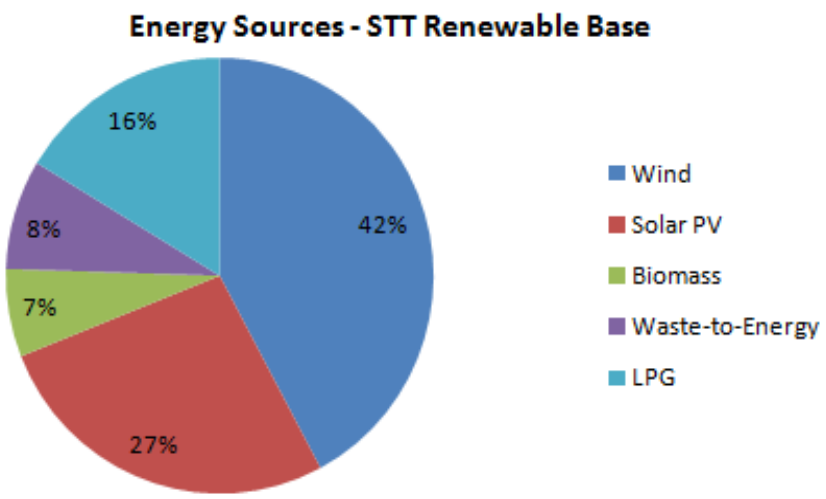


Figure 40. Energy sources – St. Thomas RE Base

Figure 41 illustrates the energy storage reserves throughout the year.

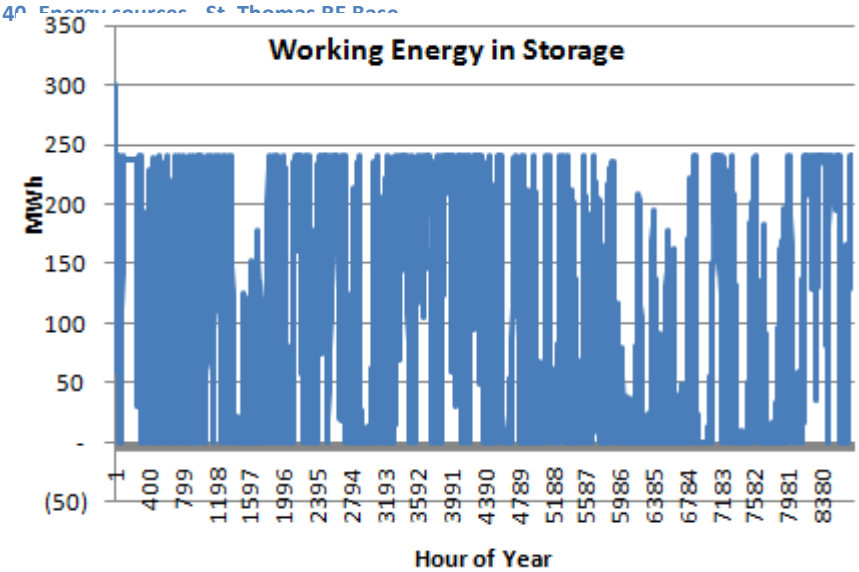


Figure 41. Working Energy in Storage

Compared with other case studies performed by Gridflex, this range of utilization suggests that the amount of storage is fairly optimized.

Curtailment

Curtailment is the forced reduction of output. All curtailment in this case was assumed to be assigned to the wind resource, although it could theoretically be shared with the "baseload" resources, depending on the economics. It is desirable to minimize curtailment because the full cost of the renewable resource has to be covered regardless of whether energy is produced or not.

In a traditional grid-connected system, wind or solar output that exceeded both contracted need and storage availability could still be discharged to the grid, albeit at whatever rate the market would pay for it. In the islanded case, curtailment is the only alternative to simply adding more storage. The model indicated that significantly more storage would have to be added, at significant cost, with only moderate reduction in curtailment.

In the case as optimized to date, curtailment was held to **13%**. Further optimization should reduce this figure.

Shortfalls and the Need to Retain Conventional Generation for Backup

The St. Thomas case with the portfolio as optimized to date left us with an annual generated energy shortfall of net 20% of delivered energy. The accompanying graph titled "Load-Serving Shortfalls" illustrates the magnitude of shortfalls by MW throughout the year. It is not coincidental that the greatest concentration of shortfall occurs in

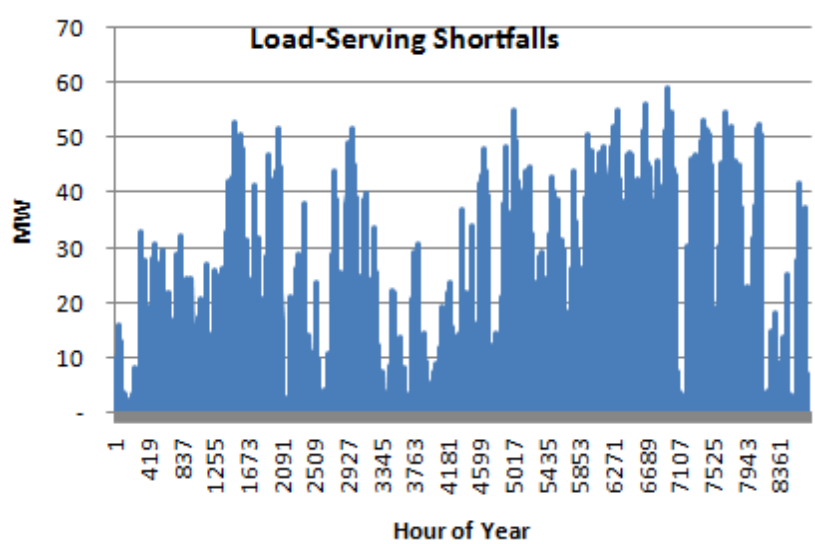


Figure 42. Load-Serving Shortfalls – St. Thomas

the fall, which is the lowest wind energy production season.

The assumption was that this energy shortfall would be made up by conventional generation retained in the portfolio, although the primary purpose for that retention is to meeting peak power shortfalls. An analysis of the frequency and magnitude of shortfalls indicates that while there is a maximum shortfall of 59 MW, the mean and median are much lower: 20 MW and 18 MW, respectively (this can be inferred from the graph above as well). The frequency of exceeding 20 MW of shortfall was 5%, and the frequency of exceeding 40 MW of shortfall was only 3%.

The above results led to the inclusion of **59 MW** of retained conventional generation for St. Thomas, although that generation would have the relatively low annual capacity factor of only 15% (which resembles that of a peaker, rather than its original combination of peaker, intermediate, and baseload functions). This should be considered only a minimum level of what conventional generation may need to be retained, however. Additional capacity may be determined to be needed to meet reserve requirements.

(2) Technical Results: St. Croix

Renewable Supply Base – Preliminary Portfolio Optimization – St. Croix Peak Load:54 MW Annual Energy Need: 318,393 MWh	
Wind	35 MW (20 MW onshore, 15 MW offshore)
Solar PV	45 MW (AC)
Biomass	10 MW
Waste-to-Energy	5 MW
Conventional Fossil	31 MW (min) capacity retained, 25,238 MWh generated (9% capacity factor)
Pumped Storage	20 MW generating / 30 MW pump / 12 hours storage (240 MWh)
Battery	5 MW generating and charging, <1 hour storage
Curtailment	14% (applied only to wind, pending further optimization)

18% of energy output was cycled through storage. With 20% losses, this means that only 4% of energy was lost through storage.

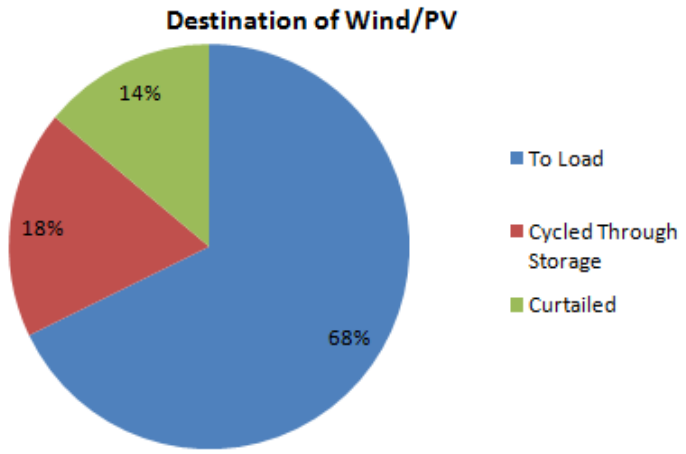


Figure 43. Wind / PV Destination - St. Croix

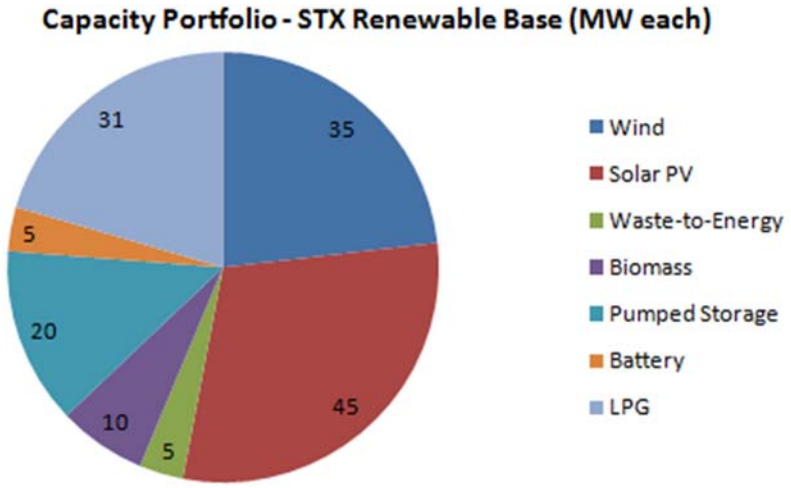


Figure 44. Capacity Portfolio - St. Croix RE Base

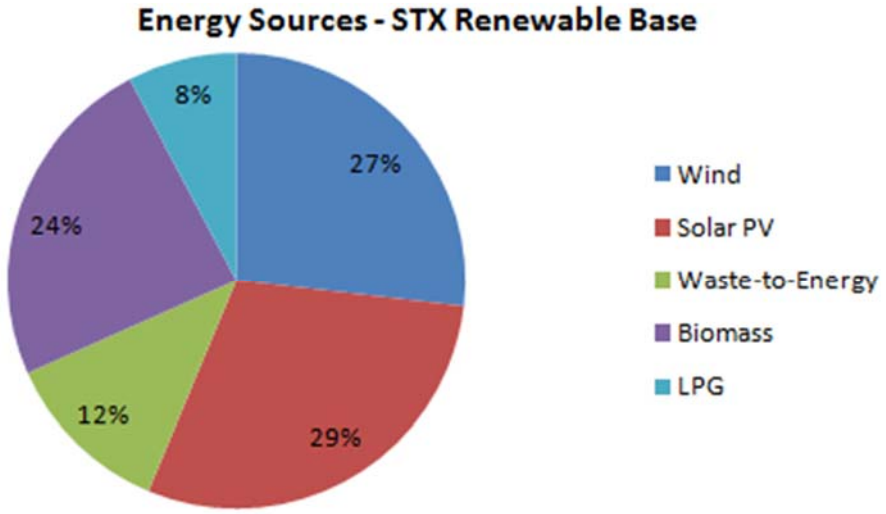


Figure 45. Energy Sources - St. Croix RE Base

Curtailment

Curtailment is the forced reduction of output. All curtailment in this case was assumed to be assigned to the wind resource, although it could theoretically be shared with the "baseload" resources, depending on the economics. It is desirable to minimize curtailment because the full cost of the renewable resource has to be covered regardless of whether energy is produced or not.

In a traditional grid-connected system, wind or solar output that exceeded both contracted need and storage availability could still be discharged to the grid, albeit at whatever rate the market would pay for it. In the islanded case, curtailment is the only alternative to simply adding more storage. The model indicated that significantly more storage would have to be added, at significant cost, with only moderate reduction in curtailment. In the case as optimized to date, curtailment was held to **13%**. Further optimization should reduce this figure.

Shortfalls and the Need to Retain Conventional Generation for Backup

The St. Croix case with the portfolio as optimized to date left us with an annual generated energy shortfall of net 9% of delivered energy. The accompanying graph titled "Load-Serving Shortfalls" illustrates the magnitude of shortfalls by MW throughout the year. It is not coincidental that the greatest concentration of shortfall occurs in the fall, which is the lowest wind energy production season.

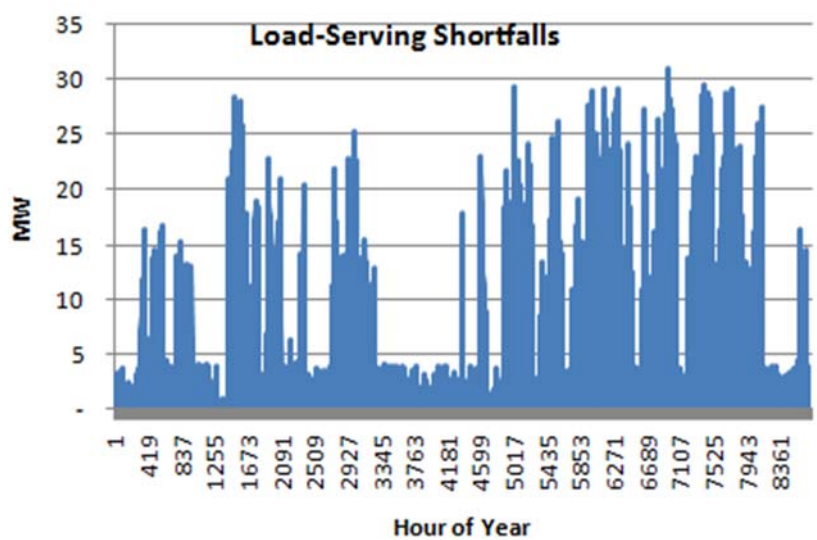


Figure 46. Load-Serving Shortfalls - St. Croix

The assumption was that this energy shortfall would be made up by conventional generation retained in the portfolio, although the primary purpose for that retention is to meeting peak power shortfalls. An analysis of the frequency and magnitude of shortfalls indicates that while there is a maximum shortfall of 31 MW, the mean and median are much lower: 10 MW and 10MW, respectively (this can be inferred from the graph above as well). The frequency of exceeding 20 MW of shortfall was 5%, and the frequency of exceeding 30 MW of shortfall was only 1%.

The above results led to the inclusion of **31 MW** of retained conventional generation for St. Croix, although that generation would have the relatively low annual capacity factor of only 9% (which resembles that of a peaker, rather than its original combination of peaker, intermediate, and baseload functions). As with St. Thomas, it should be noted that this 31 MW should be viewed only as a minimum; additional retained capacity may be needed for adequate reserves.

VIII. Economic Analysis

Capital Cost & O&M Inputs

	Capital Cost $/kW*	Fixed O&M $/kW-Yr**	Notes
Wind	$4,000 offshore/ $2,500 onshore	$35 onshore $50 offshore	
Solar PV	$2,500	$25	Recent industry studies[101] indicate that single-axis tracking costs may be under $2,000/kW.
Biomass	$5,000	$120	Fuel cost of $20/MWh was also used.
Waste-to-Energy	$8,000	$350	O&M figure includes feed supply
Pumped Storage	$3,500	$20	
Battery	$1,200	$10	Capex based on short duration storage.
Existing Conventional	$300***	$40 in Base $52 in High R.	O&M figure derived from WAPA figures, n/i fuel; Figure increased by 30% for High-Renewable model due to increased ramping costs.

*Capital cost figures were derived from a variety of recent sources, with most cited in the previous section on portfolio options. Unless otherwise noted in this document, figures came from WECC 2014, EIA 2013, or CEC 2014.

**Most technologies combine Fixed & Variable O&M figures.

*** For upgrades on aging units.

Financial Assumptions

- 9% unlevered IRR target with 100% equity financing. (In reality, most elements of the portfolio would be debt/equity financed. 100% equity was used for ease of comparing returns per energy price.)
- 25 year economic lives for all technologies (for financing purposes; pumped storage life far exceeds this; battery life is shorter)
- Corporate tax rate of 30% was applied.
- 15 years to 90% depreciation (will require refinement in future analyses)
- Market price escalation 2% (fuel); O&M escalation 2.5%
- Property tax, insurance, land costs based on common multipliers.

Transmission Losses

It has been reported that transmission losses on St. Thomas are expected to be reduced to 5% of energy sales on St. Thomas and 7.2% in St. Croix by 2016.[102] These figures were applied as a cost penalty to both the High-Renewable models and to the Baseline models. While distributed generation can result in a reduction of transmission and distribution losses, [103] we did not credit any advantage in this regard to

[101] Lazard 2014
[102] WAPA 2012a
[103] Castalia 2012

the High-Renewable models for the USVI because of the possibility that much of the new PV would be centrally located rather than distributed. Future studies will need to be performed to determine potential gains.

CO2 Penalty

While there is not consistency in pricing nor agreement on how the value of greenhouse gas emissions should be quantified, there is a market for CO2 allowances or credits. Given the direction of policy and markets, we felt that it was reasonable to include a fairly conservative figure of **$15/ton**[104]to apply as a cost to the fossil-based supply. CO2 output was calculated for each MWh based on average reported heat rates of WAPA units and figures for the CO2 value of LPG (propane) per GJ.

Impact on Electric Power Supply Cost

Nominal levelized costs for each resource in the portfolio was calculated and weighted by contribution to energy supply, with adjustment made for resource elements that don't produce original energy (pumped storage and battery). The weighted figures were summed and then adjusted for transmission loss to produce the final supply cost for the High Renewable portfolios. These were then compared with the cost of the Baseline scenario (which, to reiterate, is the Road Map scenario and not the present-day portfolio and fuel type).**As indicated on the following two pages, the cost differences between the high-renewable plus storage supply base and baseline projected supply base are clearly dramatic.**

[104] Synapse 2013

(1) St. Thomas High-Renewable Model vs. Base Case

Levelized Nominal Cost, 25 Years, Renewable Supply Base			Includes CO2		
Resource	MWh	% of Energy Supply	% of Delivered Energy	Nom Lev Cost, $/MWh	Weighted
Wind	203,250	42%	34%	$191.18	$80.72
Solar PV	128,703	27%	27%	$178.65	$47.76
Biomass	31,536	7%	7%	$130.03	$8.52
Waste-to-Energy	39,420	8%	8%	$194.48	$15.93
LPG	78,467	16%	17%	$365.37	$59.56
		100%	93%		
Pumped Storage	33,857		7%	$298.06	$21.41
Battery	657		0.14%	$1,342	$1.87
*Wind MWh is net curtailment; F4 calc accounts for wind into storage					
				Sum	**$235.76**
Energy Total*	481,376	Gross Delivered	471437		
Total w Storage	515,890				
Transmission Losses	5.0%				
Final Renewable Supply Cost					**$247.55**
Resource	MWh		% of Delivered Energy	Nom Lev Cost, $/MWh	Weighted
Wind	40,340		9%	$108.73	$9.30
Solar PV	12,870		3%	$178.65	$4.88
Biomass	0		0%		
Waste-to-Energy	39,420		8%	$194.48	$16.26
LPG	378,806		80%	$365.37	$293.58
	471,437		100%		
				Sum	**$324.02**
Transmission Losses	5.0%				
Final Roadmap Supply Cost					**$340.22**
			Cost Difference		($92.67)
			% Difference		**-27.2%**

(2) St. Croix High-Renewable Model vs. Base Case

Levelized Nominal Cost, 25 Years, Renewable Supply Base			Includes CO2		
Resource	MWh	% of Energy Supply	% of Delivered Energy	Nom Lev Cost, $/MWh	Weighted
Wind	88,044	27%	15%	$181.62	$48.74
Solar PV	96,527	29%	30%	$179.78	$52.90
Waste-to-Energy	39,420	12%	12%	$194.48	$23.37
Biomass	78,840	24%	25%	$130.03	$31.25
LPG	25,238	8%	8%	$378.33	$29.10
		100%	91%		
Pumped Storage	31,089		10%	$324.60	$31.69
Battery	657		0.21%	$1,342	$2.77
*Wind MWh is net curtailment; F4 calc accounts for wind into storage					
				Sum	**$219.82**
Energy Total*	328,069	Gross Delivered	318393		
Total w Storage	359,815				
Transmission Losses	7.2%				
Final Renewable Supply Cost					**$235.65**
Resource	MWh		% of Delivered Energy	Nom Lev Cost, $/MWh	Weighted
Wind	33,617		11%	$108.73	$11.48
Solar PV	12,870		4%	$179.78	$7.27
Waste-to-Energy	39,420		12%	$194.48	$24.08
Biomass	55,188		17%	$130.03	$22.54
LPG	177,298		56%	$378.33	$210.67
	318,393		100%		
				Sum	**$276.04**
Transmission Losses	7.2%				
Final Roadmap Supply Cost					$295.91
			Cost Difference		($60.26)
			% Difference		**-20.4%**

Combined Economic Results, All-USVI

The weighted average nominal levelized cost for the *combined* High Renewable + Storage models for St. Thomas and St. Croix was **$242.75**/MWh.

The weighted average nominal levelized cost for the *combined* projected Baseline scenario for St. Thomas and St. Croix was **$322.36**/MWh.

The percentage USVI-wide cost savings over the Baseline scenario created by adopting the High Renewable + Storage approach is **24.7%.**

IX. Environmental and Other Benefits

CO2 Reduction

The reduction in CO2 emissions in the High Renewable supply model vs. the default supply can be calculated directly through the reduction in fossil generation. The reduction from 556,105 MWh of propane-generated energy to about 103,705 MWh translates to a reduction of **417,000 metric tons** annually, or **8.3 million metric tons** over 20 years.

The USVI and other island territories and nations recognize well the importance of slowing, stopping, or mitigating the effects of greenhouse-gas driven global warming. The most obvious dangers are rising sea levels that will be destructive to coastlines, coupled with more frequent and more damaging tropical storms that compound the problem of a higher sea level. The tourism industry would be impacted directly. Other projected effects include reduced rainfall and negative effects on native flora and fauna.[105]

The contribution of the USVI's CO2 reduction to a reduced risk of catastrophic damage due to global warming would be relatively small. Nevertheless, the commitment of island territories and nations to reducing greenhouse gas emissions represents the leadership role that they are taking to the change course of events. Demonstrating that a shift to a predominantly renewable energy supply is both technically feasible and financially desirable for systems of the size as those on St. Thomas and St. Croix could bolster and inspire parallel efforts in nations small and large. Taken together with efforts globally, the USVI's efforts could make a significant difference.

Other Emissions Reductions

Fossil fuel combustion releases more than just carbon dioxide. Although newer units may be relatively efficient, they produce NOx (nitrous oxides), SOx (sulphur oxides), carbon monoxide, and PM_{10} (fine particulate matter) whose reduction results in a benefit to local air quality. This benefit should be quantified in the context of the existing power stations on St. Thomas and St. Croix.

Other Benefits

Other economic benefits to conversion to a High-Renewable Energy Supply for the USVI may include the following:

<u>Economic Stimulus from Lower Cost of Energy</u>

A 25% reduction in the cost of electricity supply over even the cleaner-than-present Road Map trajectory, if translated into a reduction in retail rates, would mean approximately $60 million annually back into the hands of USVI residents and businesses. This is not an insignificant level of economic stimulus.

[105] CARIBSAVE 2012

Job Creation

Multiple generation sites using multiple technologies will require a significant support team. The number of jobs that would be created, and the direct and indirect economic benefits associated with that job creation, would be significant and should be the subject of a detailed economic impact study.

Based on the Job Sector Analysis completed by the Renewable & Appropriate Energy Laboratory[106], job creation was measured in full-time equivalents (FTE) per MW of Renewable Energy installed. This was analyzed for utility-scale and distributed solar PV, onshore and offshore wind, biofuel (including agricultural cultivation), waste-to-energy (including generation of refuse-derived fuel), and hydro power. The preliminary review suggests that approximately 2,600 FTE jobs would be created by new renewable energy technology construction and installation (C&I) (~850 FTE per year for 3 years) and approximately 280 FTE permanent jobs would be created for operations and maintenance (O&M). These estimates are for direct jobs and do not include indirect or induced employment. Renewable energy sector literature estimates 0.78 indirect jobs for every FTE of direct employment.

Insulation from Fuel Price Uncertainty and Price Shocks

While strategies like fuel price hedging can increase short-term predictability, fuel prices are inherently volatile. The USVI have experienced this firsthand in recent years, as when oil prices more than doubled between December 2006 and July 2008. Any significant shift to renewable resources has a powerful insulative effect against future price shocks.

Increased Revenue from Ecotourism

A reputation as an "almost-all-renewable energy" tourism destination could provide U.S. Virgin Islands tourism with a new draw, building upon its current and planned ecotourism base.

[106] RAEL. 2012

X. Renewable Supply Placement

This section will outline considerations for the possible location and distribution of the renewable supply portfolio modeled in the present study.

Onshore Wind

For St. Thomas, the obvious location for onshore wind would be the Bovoni Point peninsula. The wind resource for the site has been studied, and the area is semi-industrialized. For St. Croix, the targeted amount of wind is smaller. The HOVENSA refinery area may accommodate sufficient capacity, alone or in combination with other well-exposed areas where turbine siting may be acceptable.

Offshore Wind

Offshore wind would be located off the southern coasts, within the coastal shelf (i.e., within approximately 2 miles of shore). The dominance of easterly wind would allowfor an efficient array layout. Given the relative proximity to shore, the array (or arrays) should be located where visibility from existing towns and developments will be minimal while still allowing access to shore for interconnection to the transmission system.

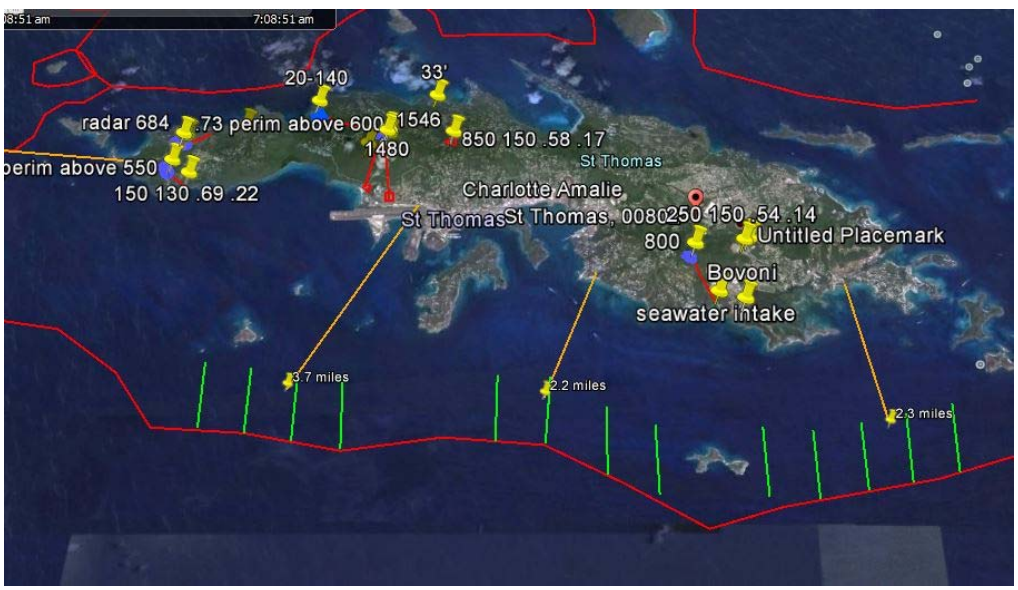


Figure 47. Potential Offshore Wind Sites - St. Thomas

The red lines in the maps indicate the estimated extent of water less than 100 feet in depth. Each of the green lines represents a row of 4 x 3 MW turbines, or 12 MW.

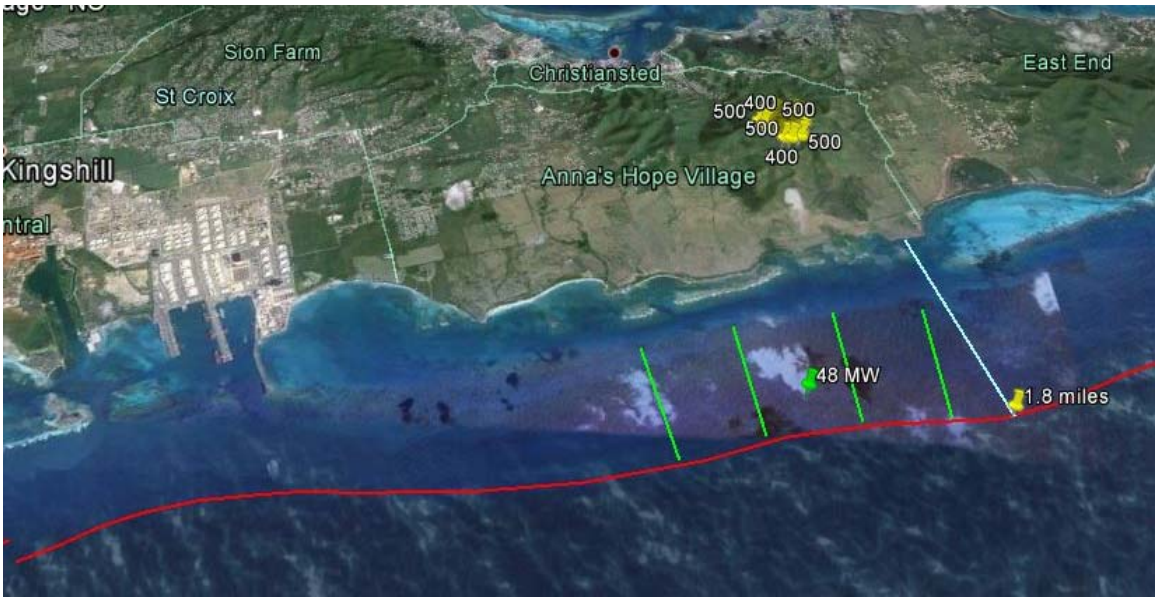


Figure 48. Potential Offshore Wind SItes - St. Croix

Solar PV

If 3 to 5 MW stations were used, 6 to 10 sites would be needed, each needing 15-25 acres. These would ideally be distributed among load centers on the periphery of the island, where insolation is greatest. As previously discussed, the HOVENSA site on St. Croix should be investigated during the Feasibility Study.

Biomass

Presumed based on the current Tibbar Energy plan, wherein the facility is located west of the Anguilla landfill in St. Croix. Energy to be generated from woody biomass and to be cultivated on approximately 1,000 acres on St. Croix and St. Thomas.

Waste-to-Energy

Presumed to be located near the two waste disposal sites—Bovoni in St. Thomas and Anguilla in St. Croix.

Pumped Storage

Siting will be driven by merit as the candidate set is narrowed down by environmental, land use, technical, and cost factors. Potential sites are described in Confidential Appendix A.

Battery

Batteries can be distributed throughout load centers as well, ideally at substations, and possibly near PV sites.

XI. Transition to a Renewable Energy + Storage Base for the U.S. Virgin Islands

General Considerations

Making the transition from the current supply base to the high-renewable supply base, complemented by storage and conventional back-up, is a long-term endeavor. The pace at which the transition can be achieved will be driven by the following factors:

- Pace of regulatory, legislative, & market adoption
- Pace of feasibility studies
- Pace of advanced studies, site selection and site procurement
- Pace of development, procurement, and construction
- Retirement of part of the existing base and minimization of stranded investment

Development of the New Base

In addition to the question of retirement of the existing base, the other side of the coin in considering the transition to the renewable + storage base is the pace at which the renewable energy and storage plant can be developed. The different elements to the new supply would have somewhat different development timelines as well. The notes below feed into the timeline chart.

Solar

The solar resource ofthe U.S. Virgin Islands is well-understood, and the technology is readily available. Construction times are short – as little as three months for a 5 MW project. Therefore, the pace of development of solar PV would be driven largely by site selection, procurement, permitting. This can be done project-by-project in serial fashion, or pursued simultaneously for multiple sites (although each site may have different issues or complications requiring adjustments in schedule).

Wind

The wind resource at Bovoni Point is now better understood, with consistent measurements taken at close to hub height. It is reasonable to expect that the resource will be similar in similarly-exposed sites of St. Croix. However, because wind energy output is highly sensitive to wind velocity, long-term wind studies are essential on a site-by-site basis. As with solar PV, construction times for onshore wind projects also relatively short, e.g., 6 months. The longer part of the development timeline will be project siting.

Offshore wind will require a longer development time because of the additional studies required to thoroughly understand siting, environmental, and visual considerations. Construction times will also be

longer – up to 30 days per turbine[107], although the proximity to shore in the case of St. Thomas and St. Croix may reduce this.

The timeline below assumes that full build-out of wind and solar would not occur until the pumped storage is ready.

Biomass & Waste-to-Energy

The Tibbar project on St. Croix is in an advanced stage of development and expected to be online by 2016. Even if a different biomass project were to materialize, it could be built on the siting and fuel supply work done for the Tibbar project. For waste-to-energy, prior experience suggests that significant time should be allowed for design & permitting. The timeline below shows WTE coming online in 2020.

Pumped Storage

Pumped storage site selection time is not a long lead-time item, but careful siting and engineering are crucial. Construction time is also fairly significant, with at least two years for smaller-scale projects, possibly longer. The timeline below assumes that pumped storage comes online in 2020.

Battery Storage

Among the advantages of battery storage is its modularity and speed of placement. The timeline below paces battery installation at about the same rate as solar PV.

Pace of Transition in Relation to Current Goals

The feasible pace of transition described herewould exceed the Road Map-based commitment to a 60% reduction in fossil fuel use by 2025.

[107] Crown Estate 2013

Potential Development Timeline through 2020 (STT & STX Combined)

		2015	2016	2017	2018	2019	2020
Wind	Resource Assessment						
110 MW	Siting & Site Acquisition						
	Environmental & Permitting						
	Finance, EPC						
	Phased Construction						
Solar PV	Project Siting & Land Acquisition						
115 MW	Environmental & Permitting						
	Finance, EPC						
	Construction						
Biomass	Resource Assessment						
7 MW	Siting & Land Acquisition						
(Assumes Tibbar)	Environmental & Permitting						
	Finance, EPC						
	Construction						
WTE	Evaluation & Design						
15 MW	Environmental & Permitting						
	Finance, EPC						
	Construction						
Pumped Storage	Site Evaluation & Selection						
40 MW	Feasibility Engineering						
	Design Engineering						
	Environmental & Permitting						
	Finance, EPC						
	Construction						
Battery	Technology Selection						
10 MW	Site Evaluation & Selection						
	Environmental Reviews, Permitting						
	Finance, EPC						
	Construction						

XII. Next Steps

The present study was limited in scope and depth. Its purpose was to provide a preliminary assessment of the technical and economic viability of the U.S. Virgin Islands transitioning from their current, nearly all-fossil electric generation base to a "high renewable" energy supply, supported by the use of bulk energy storage.

As indicated throughout this document, a wide range of follow up studies are needed to build upon the findings of this report. These studies would best be conducted in an integrated fashion in order to continue an emphasis on the most efficient and effective path to transition.

Summarizing the elements of an integrated feasibility study, they would include (but not be limited to) the following:

- Revision and refinement of the portfolio modeling analysis using island-specific hourly load profiles, wind, and solar PV data, with continued optimization of the resource balance;
- Specific wind, PV, pumped storage, and other project siting studies, including land use, environmental, engineering, and cost assessments;
- A specific study of offshore wind potential and siting, with a special emphasis on visual, environmental, turbine selection, and cost factors;
- Continued study of Waste-to-Energy prospects and their likely contribution to the renewable supply mix;
- System impact studies, including modeling and/or analysis of power quality, load balancing, transmission losses, and supply reliability and coordination with a high renewable + storage (+ fossil) base;
- Economic impact, included direct and indirect benefits as well as “stranded investment”;
- Consideration of any requirements for reform to the USVI'selectric power sector necessary to allow for a transition of the proposed scale to take place.

Development Commitments

Island Energy Innovations seeks to support the U.S. Virgin Islands government, and WAPA, in fulfilling, and exceeding, their renewable energy goals. IEI is also prepared to take as active a role in development of the renewable energy portfolio as the market will allow. At the same time, IEI recognizes that successful energy development requires long-term commitments and roles that will attract investment in pre-development, development, construction and operations. Of particular importance are the pre-development and development stages, because these represent the stages of highest risk and uncertainty.

Securing a formal and contractual role in the renewable energy and energy storage development process in the U.S. Virgin Islands through development concessions, either from the utility sector, the government, or both, will need to be an immediate priority for IEI and should be an immediate priority for the U.S. Virgin Islands.

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