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Optimization of Investments to Upgrade an Island Distribution System

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SUMMARY

An electric utility operates the power system on an island, and wishes to implement system upgrades, including the installation of distribution-level solar photovoltaic (PV) arrays and battery energy storage systems (BESS) at various sites around the island. The residential and light commercial loads are dispersed throughout the island, primarily near the coast. Currently five medium-voltage distribution feeders emanate from a single power station, which is located near the coast and accessible from the sea. Two of these feeders are primarily responsible for serving remote customers. Power generation is via four sets of tandem diesel generators. There is no connection to a larger power system from the mainland. Because it is difficult to choose among the many potential upgrade options available, including resource siting and capacity, the DER-CAM+ optimization tool was utilized to provide insight into the characteristics of an optimal solution. The tool is a recent upgrade on DER-CAM, itself a product of Lawrence Berkeley National Laboratory's research program. The upgrade includes the ability to model power distribution systems and considers possible investment options, by examining their effect on the cost of energy and on CO2 emissions. In the present study, the addition of PV and BESS at a number of pre-selected sites was considered. The analysis showed that the addition of large PV arrays, with peak power essentially matching the peak load on the system, is economically advantageous. Multiple sites allow larger overall PV deployment than a single site, as a result of distribution system constraints. The analysis also showed that the economics of optimal resource dispatch alone are not sufficient to justify the deployment of battery storage. However, battery storage could be mandatory to satisfy operational needs. Further exploration of the optimization surface revealed that, while not optimal, the cost of operation with battery storage is still lower than for the base case of diesel generation only, and not much different from the optimal case.

KEYWORDS

Island microgrid; Distribution infrastructure upgrade; System optimization; Energy storage batteries.

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Background

The mountainous moderately-sized island[1] has a characteristic dimension of about 20 km. The electric loads on the island reflect both the nature of the island's economy, as well as its mild climate. Major peaks are absent, and seasonal variations are small. The island is served by a central power station, which houses four sets of tandem diesel generators and other ancillary equipment. Five feeders carry

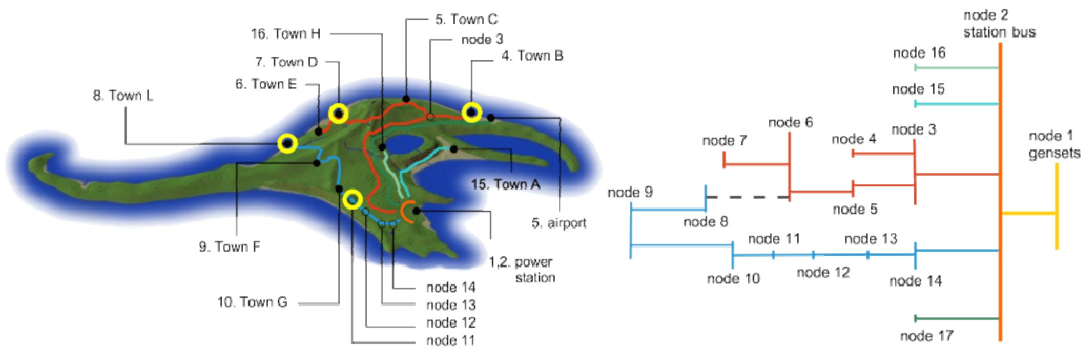

Figure 1. Physical layout of the distribution system on the island (left), showing five feeders and the major nodes on the system. The one-line diagram of the system (right) is the basis of the present study. The yellow circles indicate potential sites for photovoltaic or battery storage systems.

electricity to the loads distributed around the island, as shown in Figure 1. Town A is the main population center and houses approximately one third of the island's population, and is served by a dedicated feeder. The airport is served by a separate feeder, as is Town H. Two long feeders support the majority of other loads scattered around the island. The East feeder, shown in blue, serves Town D, a large resort town, as well as several other population centers along its length. The West feeder, shown in red, serves the agricultural towns F and G, ultimately terminating at the fishing village Town L. The ends of the East and West feeders can be linked together by a short connection between nodes 6 and 8, via a normally-open breaker, to reduce the possibility of outages in case of line or equipment failures at various locations along the length of the feeders.

The maximum load for the island is approximately 12MW. The operation of the diesel generators for one year is shown in Figure 2. The existing strategy is to operate the combination of generators that best matches the load. As can be seen by inspection of the probability density functions, the generators operate in power bands slightly lower than their nominal capacity, leaving reserve capacity for contingencies. Each set of tandem generators, from smallest to largest, operates at 0.9MW, 1.2MW, 1.8MW and 2.2MW, with individual outputs normally distributed around these levels. In the event of failure of one generator, the others are ramped up to cover the load. Load shedding measures are in place to allow ramp-up and recovery to take place.

The utility is considering the installation of distribution-level solar photovoltaic (PV) arrays and battery energy storage systems (BESS) at various sites around the island[2]. Some potential sites are shown in Figure 1. Although sites for locating the DERs (PV and BESS) are dictated by practical considerations, the choice of location among the potential options and optimization of their size are not trivial, because of the large number of parameters at play including distribution infrastructure constraints and schedules. To assist with this process, a system optimization tool developed for this class of problem was used. In the methodology section, the optimization tool is described briefly, and the inputs and constraints that define the problem are outlined. The results are discussed in the subsequent section. Conclusions about the use of this optimization tool are finally given, along with recommendations for further study.

[1] The island and its population centers are fictitious, and used only for illustrative purposes, although they are based on a real situation.

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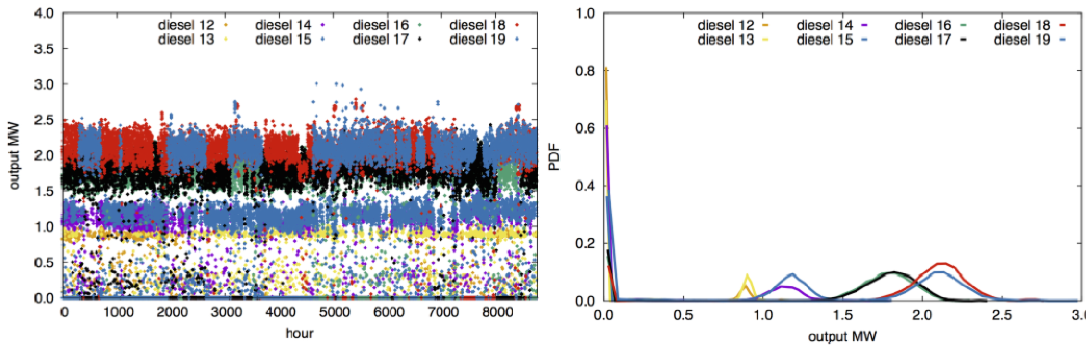

Figure 2. Operation history of the four tandem gensets at the central power station (left) and probability density function for their operation (right). When operating, the power level of each generator is approximately normally distributed. The PDFs also reflect that generators may be turned off on occasion.

Methodology

The problem studied here is to determine the optimal deployment of PV and BESS on the island from an economic point of view. The parallel process necessary to define the basis of a full system design, namely an operational study that takes into account system dynamics, is outside the scope of this study. The tool used in this study is DER-CAM+, and evolution of the well-known DER-CAM tool that resulted from several years of development at Lawrence Berkeley National Laboratory [1]. The inputs required to perform a system optimization using DER-CAM+ are: (1) historical loads, defining the use of various forms of energy at each of the nodes; (2) electricity and fuel tariffs or costs; (3) technology data, including operating characteristics of existing or potential generation and storage equipment, and related costs; (4) weather data, to determine the capacity and characteristics of renewable resources such as solar PV or wind turbines. For the purposes of this study, the "investment planning" option of DER-CAM+ was used. This option produces a recommendation for optimal deployment of DERs, which minimizes levelized energy costs, carbon emissions or a linear combination thereof. It is important to note that the optimization of the equipment deployed calculates optimal operating schedules for each realization of deployed equipment. Each of the optimal operating schedules must be such that the load is met within the constraints of the equipment operating characteristics and the ability of the network to carry electricity from generation to load.
In this study, the only loads that are considered are electrical ones, although DER-CAM+ is also capable of treating thermal loads such as heating and air conditioning.

The utility provided total hourly electric loads for each feeder. To determine the load at each node, which is the required input for DER-CAM+, a share of the total feeder load is allocated to the node, in proportion to the fraction of population that could be allocated to that node. Population numbers for each major node on the feeder were estimated based on reported population data available online. After loads for each node are extracted, they are processed to calculate typical monthly loads, characterized as weekday, weekend or peak. The distinction between weekend or weekday is necessary because typical electricity tariffs are structured accordingly. The peak loads are necessary so that DER-CAM+ can ensure sufficient resources to meet loads, including sufficient reserve capacity. Ultimately, for each node and for each month, three 24-hour load profiles are produced, representing weekday, weekend and peak conditions. An example of these is shown in Figure 3. The load profiles for Town D are essentially as expected, with a moderate mid-morning peak and a strong late-evening peak, matching tourism-related activities. Load profiles for nodes on other feeders are similar. Also noteworthy is the fact that peak loads are not very different from typical weekday and weekend loads. Finally, the January load seems to be significantly higher than for other months perhaps as a result of a higher number of tourists for this month.

The characteristics of the existing diesel gensets were extracted from the data provided by the utility and from other sources [2]. Efficiency curves were determined using data on hourly energy production and cost, along with associated fuel costs. The operating characteristics of the gensets are summarized in Figure 4. In the optimization, average efficiency values for each genset type were used.

For the PV arrays, a cost of $2,500 per peak kW was assumed, with an expected lifetime of 30 years.

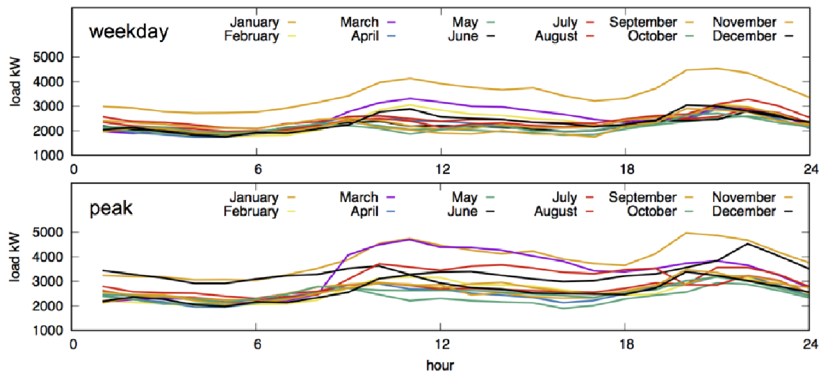

Figure 3. Typical weekday and peak loads for the Town D node. Weekend loads are very similar to weekday loads. Note the mid-morning and late-evening peaks, and the January anomaly.

For the BESS, a basic cost of $500/kWh and lifetime of 5 years were assumed, however other cost and lifetime parameters were also explored. The efficiency for the BESS was 0.9 for both charge and discharge cycles, while the maximum power input/output was limited to 0.25 of the maximum capacity per hour. A minimum state of charge of 0.3 was also assumed. The characteristics of the electrical network are given in terms of the nodal admittance matrix. From this, the impedance matrix can be calculated by removing row and column corresponding to the slack node, inverting and replacing the deleted row and column with zeros. A matrix of network branch capacities was also input as a constraint.

For the weather data, a TMY2 file from a meteorological database was obtained for the island. To construct 24-hour solar, wind speed and temperature profiles for each month, the TMY2 data for each month were averaged for each hour. While it should be noted that this process tends to remove sudden changes (e.g. cloud-driven irradiance variability), this level of data resolution is not required for economic optimization.

	min power	max power	sprint power	eff'y	O&M cost	cap cost	lifetime
units	MW	MW	MW	NA	$/MWh	$K/MW	years
12+13	0.84	1.40	1.60	0.346	17	300	20
14+15	0.96	1.84	2.00	0.360	16	290	20
16+17	1.43	2.51	2.70	0.373	15	280	20
18+19	1.71	3.10	3.50	0.381	14	270	20

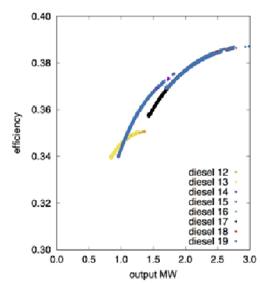

Figure 4 : Characteristics of the diesel gensets at the power station.

Results and discussion

A total of nine scenarios were explored in the basic optimization process. Case 0 is the base case, with diesel gensets only. For this option, as for all other ones, the existing generators were forced. Thus, the only optimization possible was for the generator schedules. The result of this optimization is the baseline optimal cost of operating the diesel generators. For cases 1, 3, 5 and 7, the installation of PV arrays at nodes 7, 7+8, 4+7+8, 4+7+8+11 respectively were allowed. No constraints on the array size were placed. Cases 2, 4, 6 and 8 are the same as 1, 3, 5 and 7, except that battery storage is allowed in conjunction with the PV arrays, at the same locations and also with no size constraints.

The CO2 emissions were also calculated for each case, although their minimization was not explicitly required. Also, for the basic optimization, no CO2 tax was assumed. The results of the basic optimization runs are shown in Figure 5. The result that stands out is that battery storage is not selected in any of the cases. The reason is that it does not minimize energy cost, as will be discussed later. On the other hand, the installation of PV is highly recommended by the model, and provides substantial economic benefits as well as reduction in emissions. For case 1, with only one site available for PV, DER-CAM recommends the installation of 8.6MW of PV. For this case, the annual total energy cost saving is 12% of the base case cost. The combined fuel and O&M savings are 22.5%, meaning that the initial investment cost for the PV installation can be recovered in less than 10 years. In addition, CO2 emissions are 26% less than the original emissions. For case 7, where PV is allowed at 4 sites, a total of 11.7MW of PV capacity is installed, with an annual total energy cost saving of 15.8% compared to the base case, and 35% reduction of CO2 emissions. The size of the PV arrays ranges from 2.1MW to 3.3MW, meaning that siting at individual locations could be easier.

It is instructive to inspect some of the calculation results from an operational point of view, to better understand the outcome of the optimization. DER-CAM processes large amounts of data, and the output is correspondingly substantial, so it can be difficult to decide what to inspect. For this work, the voltages at the end of the feeder were considered important, as they could be representative of potential difficulties with high PV penetration. Also, power flow along sections of the feeder could be significant to identify constraints.

	overall for system				levelized energy cost for upgrade installation							
					loc7		loc8		loc4		loc11	
Case #	total	fuel	CO2	losses	PV	BESS	PV	BESS	PV	BESS	PV	BESS
	% of base case total			%	% of base case total							
0	100.00	77.73	100.00	3.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	88.04	57.25	73.67	3.10	10.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	87.88	56.89	73.21	3.11	10.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	86.01	53.00	68.22	3.94	4.07	0.00	9.07	0.00	0.00	0.00	0.00	0.00
4	86.04	53.05	68.27	3.71	3.78	0.00	9.35	0.00	0.00	0.00	0.00	0.00
5	84.30	50.28	64.70	4.93	3.94	0.00	5.44	0.00	5.06	0.00	0.00	0.00
6	84.27	50.06	64.43	5.65	3.56	0.00	5.86	0.00	5.23	0.00	0.00	0.00
7	84.22	50.30	64.73	6.28	4.07	0.00	2.56	0.00	3.73	0.00	3.97	0.00
8	84.22	50.30	64.73	6.28	4.07	0.00	2.56	0.00	3.73	0.00	3.97	0.00

green = option enabled | red = option disabled

Figure 5. Annual energy costs, emissions and losses associated with various optimized cases, in comparison to the base case. Higher losses for high PV penetration are due to PV curtailment.

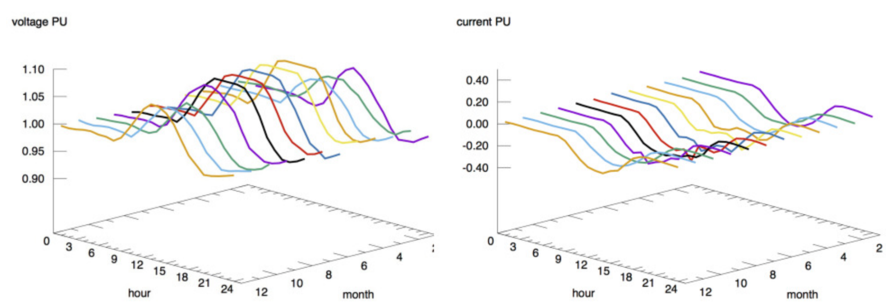

Figure 6. Voltages at Town D (left) and branch currents between nodes 3 and 4 (right), for case 5.

The voltage profiles near the PV show significant voltage variations over the course of the day, with voltages close to 1.05pu during peak PV operation. For some of high PV production and smaller loads, there is evidence of significant PV curtailment by the model. The branch current between node 3 (Town B) and node 4, resulting from the flow of PV power to Node 5 (Town C), reaches a magnitude of 0.28pu, equal to the branch carrying capacity, limiting the size of the possible PV installation without upgrades to the grid infrastructure.

Voltages at the end nodes are currently managed using load tap changers (LTCs) at the transformers. In the current configuration, they are needed to correct voltage drops resulting from the long distribution feeders. With high PV penetrations, LTCs could be used to also compensate for high voltages caused by PV generation. However, it would be unreasonable to attempt to manage voltage variations from cloud-driven PV intermittency using LTCs. Instead, this condition could be managed either with careful curtailment in certain weather conditions (potentially leading to substantial loss of PV power production) or via batteries, as has been done in some instances [3]. Also, reactive loads are not considered here, and their effect should be investigated in further studies.

Although the DER-CAM+ results do not recommend the installation of batteries on economic grounds, operational requirements with high PV penetration make batteries desirable or even mandatory. It is therefore interesting to assess the additional cost of battery installation. Given that the presence of a BESS would allow a different operating schedule from the case of PV alone, leading to altered economics, just adding the annual cost of a BESS to the optimized system with PV alone would not provide an accurate estimate of the PV + BESS system cost. Instead, the optimized cost with forced BESS installation, as a function of the size of the BESS and of the unit cost of the BESS was explored. To make conditions slightly more favorable to battery installation, a CO2 tax of $100/ton was applied, and battery life was extended to 10 years. Case 2 was considered. Results are shown in Figure 7.

For a battery unit cost of $500/kWh, the minimum annual energy cost of 114% of the base case is achieved with no battery installation. As installed battery size increases from zero, there is a relatively steep increase in cost until a battery size of about 3MWh. At this point, the rate of cost increase flattens until a local minimum is reached at approximately 10MWh. After this, the annual cost begins to increase again. At 10MWh, the annual energy cost is approximately 115.8% of the base case, a modest increase over the cost with no battery, but with significant added advantages including the ability to smooth PV, added resilience, and the capacity to deal with contingencies without the need for load shedding. With a battery unit cost of $350/kWh, there is a steep increase in annual cost for small battery sizes, but then the cost decreases to the original PV-only value at a battery size of 8 MWh. After this, cost begins to increase again with added battery capacity. Finally, with a unit cost of $250/kWh, the initial steep cost increase for small batteries is followed by decreasing annual energy costs, which begin to flatten out at a battery capacity of 30MWh. Finally, the operating schedule of a battery, for an installation size of 13.4MWh is shown in Figure 7. During the night, the battery supplies power locally, when the PV is not available, while it charges during the day at a fixed rate, equivalent to the maximum charge rate.

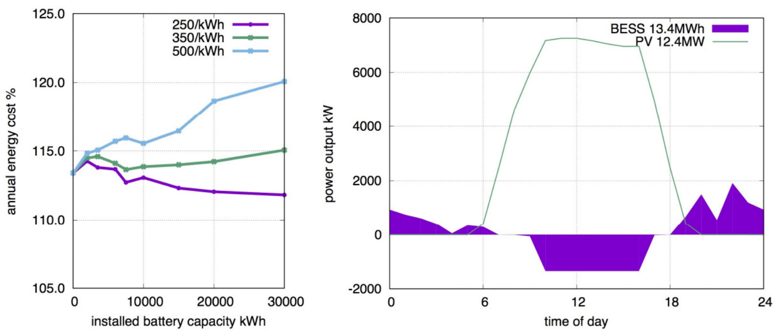

Figure 7. Annual energy cost, with CO2 tax, as a function of installed battery capacity for Case 2 (left), and typical battery and PV operating schedules for a battery size of 13.4MWh (right). The annual cost with diesel only is 135%.

Conclusions

The DER-CAM+ tool was applied to the problem of optimizing DER deployment on an island grid, using data supplied by the utility as an input to the optimization process, and reasonable assumptions when data were not available. DER-CAM+ has provided useful insight into the economics of combined PV and battery systems on an island. Specifically, the low cost of PV power makes it desirable to install significant PV capacity, with peak power equivalent to the system peak load. While the annual energy cost is minimized by PV-only installations, it is not practically feasible to run an island grid with no battery support, because it would be very difficult to deal with cloud-driven PV intermittency. However, DER-CAM+ analysis indicates that the addition of battery capacity that would be sufficient to deal with intermittency does not result in major increases in annual energy cost, and that even with substantial battery capacity, annual energy costs can be significantly lower than with diesel alone, especially when CO2 taxes are considered.

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