Matching Energy Storage to Small Island Electricity Systems: A Case Study of the Azores

by

Daniel Frederick Cross-Call

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Author ....
Technology and Policy Program, Engineering Systems Division
August 9, 2013

Certified by ....
Stephen Connors
Director, Analysis Group for Regional Energy Alternatives, MIT Energy Initiative
Thesis Supervisor

Certified by ....
Ignacio J. Pérez-Arriaga
Visiting Professor, Engineering Systems Division
Thesis Supervisor

Accepted by ....
Dava Newman
Professor of Aeronautics and Astronautics and Engineering Systems
Director, Technology and Policy Program

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Abstract

Island economies rely almost entirely on imported diesel and fuel oil to supply their energy needs, resulting in significant economic and environmental costs. In recognition of the benefits of clean energy development, many islands are pursuing ambitious goals for renewable energy. For example, the Azores Islands of Portugal have set a goal to achieve 75% renewable energy by 2018. Despite significant environmental and economic benefits, however, the introduction of renewable energy sources introduces new operating challenges to island power systems, including intermittent and uncertain generation patterns. This research investigates energy storage on small island power systems under scenarios of increasing penetrations of variable-output wind. The analysis applies a least-cost unit commitment model to three Azores island networks (São Miguel, Faial and Flores), in order to determine expected cost savings from introducing energy storage onto those systems. Modeling results indicate that renewable energy coupled with energy storage can produce significant savings in operating costs on island electricity systems—above those levels achieved from renewable generation alone. Furthermore, the research suggests that storage power (in terms of available megawatts for discharging energy) is more critical than storage capacity (megawatt-hours of available storage) for achieving costs savings and clean energy goals. The largest impacts from storage will come from relatively small-sized storage installations, above which there is a diminishing return from storage.

Thesis Supervisor: Stephen Connors
Title: Director, Analysis Group for Regional Energy Alternatives, MIT Energy Initiative

Thesis Supervisor: Ignacio J. Pérez-Arriaga
Title: Visiting Professor, Engineering Systems Division

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Contents

1 Introduction **13**

1.1 Motivation for research 13

1.2 Problem statement 15

1.3 Azores Islands 15

1.4 Key findings 17

2 Background **19**

2.1 Island concerns 19

2.2 Island electricity systems 22

3 Policy context **29**

3.1 Carbon lock-in on islands 29

3.2 EU climate and energy policy 31

3.3 Power system reliability criteria 32

3.3.1 Security of supply on power systems 32

3.3.2 Reserve requirements 34

3.4 Policy options 36

4 Energy storage overview **39**

4.1 Performance and uses of energy storage 39

4.2 Description of storage technology options 42

4.3 Market development for energy storage 46

5 Context for study: Azores Islands **49**

5.1 Islands overview 49

5.2 Economy of the Azores 53

5.3 Political structures 54

5.4 Azores clean energy goals 55

5.5 Azores electric power systems 56

5.5.1 Electricity end uses and demand profiles 57
5.5.2 Island generation portfolios 59
5.5.3 Clean energy development 61
5.6 Prior Azores energy planning studies 63
5.7 Azores islands for analysis 64

6 Research methods **71**
6.1 Prior work 71
6.1.1 Modeling of power systems 71
6.1.2 Modeling of island power systems 74
6.1.3 Modeling of energy storage 74
6.2 Description of model for island power systems 76
6.2.1 Mathematical formulation 76
6.2.2 Outputs of model 82
6.3 Data sources and assumptions 83
6.3.1 Input assumptions 83
6.3.2 Model calibration 92

7 Results **93**
7.1 Generation Dispatch 93
7.2 Cycling of generation units 98
7.3 Renewable energy generation 102
7.3.1 Wind curtailments 102
7.3.2 Total renewable generation 103
7.4 Annual operating costs and savings 106
7.5 Sizing of Storage 109
7.6 Value of Storage 112
7.7 Sensitivity analysis 116

8 Conclusions **123**
8.1 Summary of key findings 123
8.2 Discussion 126

A Sample GAMS code **129**

List of Figures

1-1 Map of the Azores 16

4-1 Grid services from energy storage 41
4-2 Comparison of energy storage technology performance 42

5-1 Map of São Miguel 50
5-2 Map of Santa Maria 50
5-3 Map of Terceira 51
5-4 Map of Graciosa 51
5-5 Map of São Jorge 52
5-6 Map of Pico 52
5-7 Map of Faial 52
5-8 Map of Flores 53
5-9 Map of Corvo 53
5-10 Electricity demand profile on São Miguel (2010) 58
5-11 Electricity demand profiles on Faial and Flores (2010) 59
5-12 Historical fuel costs in the Azores compared to Portuguese average . . 60
5-13 Weekly demand profiles on São Miguel, Faial and Flores 65
5-14 São Miguel generation profiles (2010) 67
5-15 Faial generation profiles (2010) 68
5-16 Flores generation profiles (2010) 69

6-1 Hourly load shapes over one week on São Miguel 84
6-2 Historical and forecasted annual peak load 85
6-3 Weekly wind generation on Flores (2010) 88
6-4 Histogram of weekly wind generation on Flores (2010) 89
6-5 Hourly wind shapes of selected weeks for modeling of wind forecast . 89
6-6 São Miguel historical generation compared to model results 92

7-1 São Miguel generation dispatch without storage 95

7-2 São Miguel generation dispatch with 40MW/200MWh of storage . . . 95
7-3 São Miguel generation dispatch with 40MW/200MWh of storage . . . 96
7-4 Faial generation dispatch with 6MW/80MWh of storage 97
7-5 Flores generation dispatch with 250kW/2.5MWh of storage 98
7-6 Annual ICE unit starts on São Miguel 99
7-7 Annual ICE unit starts on Faial 100
7-8 Annual ICE unit starts on Flores 101
7-9 Renewable generation impact from storage on São Miguel 104
7-10 Renewable generation impact from storage on Faial 105
7-11 Renewable generation impact from storage on Flores 106
7-12 Annual operating cost savings from storage on São Miguel 107
7-13 Annual operating cost savings from storage on Faial 108
7-14 Annual operating cost savings from storage on Flores 109
7-15 Savings by size of energy storage on São Miguel with 70 MW of wind 110
7-16 Savings by size of energy storage on Faial with 12 MW of wind 111
7-17 Savings by size of energy storage on Flores with 2 MW of wind 112
7-18 Savings versus investment cost of storage on São Miguel 114
7-19 Savings versus investment cost of storage on Faial 115
7-20 Savings versus investment cost of storage on Flores 116
7-21 São Miguel generation dispatch with geothermal expansion 121
7-22 São Miguel generation dispatch with geothermal expansion and storage 121

8-1 Example of operating cost savings and optimal size of energy storage 126

List of Tables

1.1 Comparison of islands analyzed 16

4.1 Performance and cost of energy storage technologies 43

5.1 Electricity generation plants in the Azores 61
5.2 Size comparison of São Miguel, Faial and Flores 65

6.1 Historical and forecasted annual peak load growth 84
6.2 Generator performance assumptions for São Miguel 86
6.3 Generator performance assumptions for Faial 86
6.4 Generator performance assumptions for Flores 86
6.5 Variable cost of renewable energy from PPAs and feed-in tariffs . . . 87
6.6 Modeling scenarios for total wind capacity 88
6.7 Weeks selected for modeling of wind forecast 89
6.8 Example of storage sizing assumptions 91

7.1 Estimated annual wind curtailments on São Miguel 102
7.2 Estimated annual wind curtailments on Faial 103
7.3 Estimated annual wind curtailments on Flores 103
7.4 Storage power to achieve maximum operating cost savings on São Miguel 114
7.5 Storage power to achieve maximum operating cost savings on Faial . 115
7.6 Storage power to achieve maximum operating cost savings on Flores . 116
7.7 Impacts from higher fuel costs; São Miguel with 9 MW wind 117
7.8 Impacts from higher fuel costs; São Miguel with 70 MW wind 118
7.9 Impacts from lower demand; São Miguel with 9 MW wind 118
7.10 Impacts from lower demand; São Miguel with 50 MW wind 119
7.11 Impacts from geothermal expansion; São Miguel with 9 MW wind . . 119
7.12 Impacts from geothermal expansion; São Miguel with 30 MW wind . 120

Chapter 1

Introduction

1.1 Motivation for research

Island economies rely almost entirely on imported diesel and fuel oil to supply their energy needs, resulting in significant economic and environmental costs. Islands depend on oil not only for transportation, but also to generate electricity; on many islands, diesel and fuel oil supply nearly 100% of electricity generation. Due to the high costs of transporting oil to remote islands and the relatively small quantities they purchase, islands frequently pay above global market prices for oil. Islands' reliance on imported oil results in energy security challenges in the form of high costs for electricity, vulnerability to oil price shocks and, in many cases, significant trade imbalances. In order to address these problems, island governments around the world are looking for renewable energy alternatives to petroleum-based fuel.

Given their vulnerability from rising sea levels and shifting weather patterns, islands are also leading advocates for measures to reduce greenhouse gas emissions. Indeed, oil-fired electricity generation has a high carbon intensity compared to other generation technologies and, like other fossil fuels, oil use will need to be drastically reduced or eliminated in order to meet climate change goals. Yet, given the overwhelming greenhouse gas contributions from mainland industrialized societies, any emission reductions that islands undertake will have a negligible effect on reducing climate change impacts. Due to their heightened vulnerability and small economies, islands will bear disproportionate costs from climate change compared to their contribution to global greenhouse gas emissions, and climate change alone provides limited incentive for islands to invest in clean energy systems. Moreover, legacy infrastructure and conventional wisdom biased toward traditional electricity system designs has created a situation of "carbon lock-in" from which it is difficult for islands to escape.

Coupled together, however, the dual problems of energy security and climate change give islands a strong interest in adopting clean energy systems. Where climate change is a global problem for which islands have limited ability to directly solve or alleviate, oil dependence can be addressed by local energy solutions. Compared to transportation and other energy needs, the case for clean energy investments is especially strong for electricity systems on islands due to the availability of alternative technologies such as wind and solar generation. Indeed, numerous studies have demonstrated that renewable energy systems can be cost competitive with oil-fueled electricity generation on islands.[1, 2] In recognition of these potential benefits, many islands are pursuing ambitious goals for clean energy development, including a significant number moving forward with planning and construction of renewable generation projects.

Although renewable generation can provide substantial environmental and economic benefits, the introduction of these technologies introduces new operating challenges to electric power systems. This is especially true for island systems. Renewable technologies such as wind and solar have variable output due to fluctuations in weather patterns, which can result in mismatches between generation supply and electricity demand and lead to difficulty maintaining reliability on the grid. To manage those challenges, systems with high penetration of variable generation have a greater need for operational flexibility and reserve requirements.[3] Compared to mainland systems, islands experience greater variability in both electricity load and renewable generation, making them particularly vulnerable to reliability violations.[4] This situation requires careful analysis and system planning to determine the best generation portfolios for island energy goals, while ensuring that reliability is maintained or even improved.

In addition to the advantages for the islands themselves, clean energy projects on islands offer lessons for power system planners elsewhere. Due to their isolation from larger systems and the ability to make significant change relatively quickly, islands can serve as "test beds" or "living labs" for changes that are needed across the global electricity sector. Islands have the potential to become places of demonstration for new technologies, system designs, and business concepts, which can then be refined and exported to other networks. If islands succeed in solving their own dependence on fossil fuels, they will not only achieve more low-carbon and efficient economies at home, but can also reverse historical trade imbalances to become exporters of clean energy knowledge and designs to larger industrial societies.

1.2 Problem statement

Where variable renewable generation is introducing new supply-demand balancing challenges and the need for greater operational flexibility, energy storage provides a partial solution. Energy storage can store excess electricity when it is generated in low-demand periods such as overnight, then return it to the grid in high-demand periods when renewable or other generation sources are unavailable or non-economic. In addition, certain storage technologies can provide fast-response services when perturbations in generation or demand might otherwise cause violations in frequency and voltage standards on the network. However, no single storage technology is suited to provide all network services. Furthermore, many storage technologies have yet to be proven at scale and under real operating conditions. Therefore investment decisions in storage need to be made with careful consideration to the needs they will serve.

This research investigates energy storage on small island power systems under scenarios of increasing penetrations of variable-output wind. Storage is analyzed with attention to the optimal sizing of storage installations according to parameters for energy capacity and power. The analysis applies a least-cost unit commitment model to three Azores island networks (São Miguel, Faial and Flores), in order to determine expected cost savings from introducing energy storage onto those power systems. In addition to total system cost, other impacts from storage are analyzed including on/off cycling of generating units, avoided wind curtailments and total renewable generation. The three selected islands provide different system sizes and legacy generation portfolios, based on which comparisons can be made and insights drawn for how the applications and value of storage might change across different islands.

1.3 Azores Islands

The Azores are an archipelago of nine Portuguese islands in the Atlantic Ocean, about 1,500 km west of mainland Portugal, with a population of around 245,000 people. The islands are clustered in three major groups: the eastern group composed of two islands including the largest island of São Miguel, the central group composed of five islands, and the western group with two islands. The full archipelago stretches 600 km along a southeast-to-northwest axis. See Figure 1-1 for a map of the Azores Islands.[5]

The Azores offer an attractive setting for clean energy development, given the

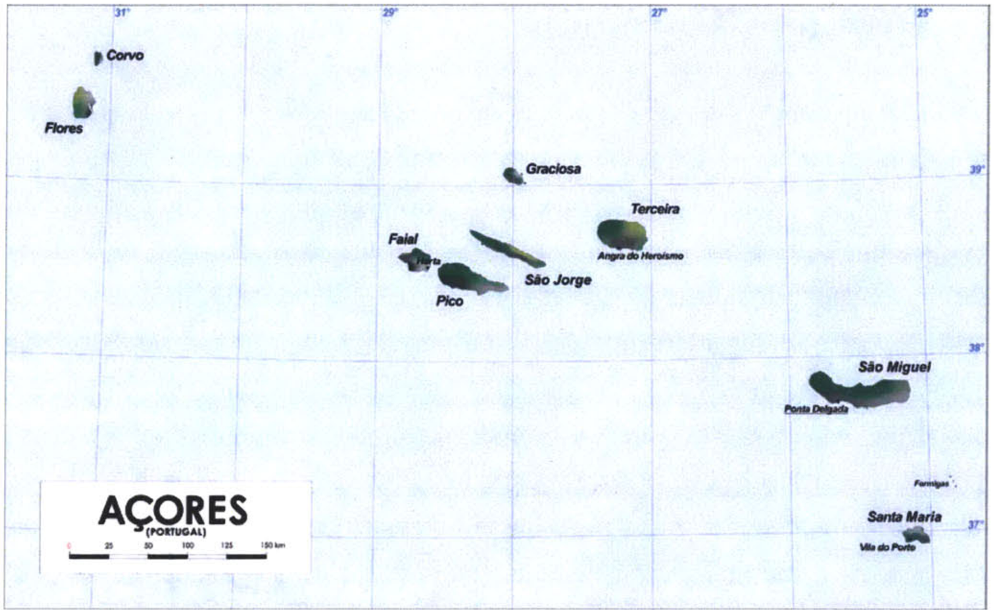


Figure 1-1: Map of the Azores

islands' progressive electric utility and local government, abundant clean energy resources, and growing energy needs. Although not official law, a former president of the Azores set a goal to achieve 75% renewable electricity on the islands by 2018, with an intermediate goal of 50% renewable by 2015. In that pursuit, the Azores have added 20 MW of wind capacity in recent years, providing around 5% of annual generation.[6] The islands also have modest amounts of hydro generation capacity and two geothermal power plants, with potential for more renewable capacity.

This research focuses on three of the Azores islands, selected for the range of sizes and existing generation portfolios that they represent. Table 1.1 provides summary data for the three islands under review.

Island	Size (sq. km)	Population (approx.)	2010 Peak Load (MW)	2010 Generation from Oil (%)
São Miguel	750	140,000	74.2	57%
Faial	170	15,000	9.4	93%
Flores	140	4,000	2.1	51%

Table 1.1: Comparison of islands analyzed

São Miguel is the largest island in the Azores, both in size and population. The island is home to the regional government, as well as a growing tourist economy and traditional sectors of fishing and farming, giving it it the most diverse economy and energy needs of the nine islands. São Miguel also has a relatively diverse generation portfolio, which includes two geothermal power plants that supply around half of load. The second island analyzed is Faial, a small island of around 15,000 people with a mainly agricultural economy. Faial currently relies almost entirely on oil-burning power plants for electricity, making it an interesting test case for the ability to integrate renewables into an undiversified generation portfolio. The third island, Flores, has a very small population of around 4,000 people and peak load of barely 2 MW. Due to its small size, Flores, exhibits greater variability in intra- and inter-hour electricity demand than other systems, possibly making it a strong candidate for power quality and load smoothing applications of energy storage. Further descriptions of the islands and their electricity systems can be found in Chapter 5.

1.4 Key findings

From the cases studied, modeling results suggest a high value of energy storage on island power systems, mainly for reducing operating costs and achieving higher shares of renewable generation. The cost savings are attributable to a combination of storage effects, including fewer start-ups and shut-down of generating units and lower consumption of expensive fuel oil and diesel. The higher share of renewable generation is due to the ability of storage to shift energy from hours in which it is generated to later hours when it is needed, resulting in less renewables curtailment. In addition, renewable generation increases due to the provision of operating reserves from storage rather than requiring additional thermal units to remain online, thus further reducing renewable curtailment. The use of storage for maintaining reserve requirements suggests an "option value" of storage, which might be greater in actual practice than deterministic model results would suggest. Relatively small storage installations are found to offer significant benefits on islands, beyond which there is a diminishing return to storage size. Detailed research findings and a discussion of results can be found in Chapters 7 and 8.

Chapter 2

Background

Islands across the world are undertaking programs to develop clean energy infrastructure and ween themselves off fossil fuels. These islands are motivated by the dual problems of climate change vulnerability and high costs from fossil fuel imports. Islands are challenged in their clean energy efforts, however, by high capital costs for renewable energy systems, lack of familiarity with emerging technologies, and engineering as well as economic difficulties inherent in small electric power systems that lack the benefits of scale. Furthermore, the unique characteristics of each island present limitations to the portability of solutions from one island to the next. This chapter discusses these and other issues confronted by islands, in an effort to better understand the context for electric power system planning on islands.

2.1 Island concerns

Climate change vulnerability

Climate change presents islands with a strong interest in integrating renewables into their energy systems, although any efforts by islands to address climate change will be subordinated to the global ability to deal with the challenge. Climate change is a drastic example of a "tragedy of the commons" [7] and a global negative externality, in which the full social cost of our consumption of carbon-intense fossil fuels is not captured in the price that consumers pay for their use. The extremely diffuse nature of those costs—not limited to any individuals or countries but truly global—and the unequal impacts between the present time when emissions occur and a distant future when harms will be most severe, results in a situation for which there is limited incentive to address the problem on a meaningful scale. Although it would be possible to mitigate the impacts of climate change if the world undertakes large-scale decarbonization of human activity, the political, economic, and energy system changes that are required to do so have been slow to develop. Mancur Olson describes this type of political situation as a "collective action" problem, because solutions require significant coordination by dispersed interests (e.g. interest groups such as environmentalists, at-risk populations, future generations that have limited representation) in order to effectively lobby for effective policy change, whereas the interests for the status quo are naturally more consolidated and powerful (e.g. large energy companies, industry groups, and industrialized societies that have the most to lose).[8] Island societies represent one interest on the side of advocates for climate change mitigation, because their contribution to total greenhouse gas emissions is relatively small while the costs are high.

The full impacts from climate change are varied and not completely known, but there is widespread agreement that they will include a rise in sea levels and increase in the frequency and severity of tropical cyclones. As a result of thermal expansion of ocean waters, coupled with the melting of polar ice caps, sea levels are predicted to rise by as much as one meter in the next century, and possibly 4-6 meters over hundreds of years.[9] The rise in sea levels will harm people and nations around the world, but the impact will be felt most acutely by island societies where a large portion of land lies below the affected zone. Other climate change impacts might vary between positive and negative for different islands depending on their location and existing climates. Regardless, it is reasonable to expect significant costs for many islands, especially in cases where a change in climate and increased severity of tropical storms would be detrimental to tourist economies, disruptive to other social and economic activity, and impose damage on major infrastructure.

This situation of heightened vulnerability provides islands with a commensurately greater interest in preventing climate change. Further, islands tend to be less dependent on carbon-intensive economic sectors such as fossil fuel extraction and heavy industry. Consequently, most islands individually—and certainly islands collectively across the world—can be considered net losers in likely climate change scenarios and therefore have a strong interest in reducing greenhouse gas emissions. Islands are, however, negligible contributors to global greenhouse gas emissions. This means that any costs incurred from reducing emissions are unlikely to be recovered because the benefits of mitigation activity are so diffuse across the world and more significant polluters are not taking major action themselves.

Even so, islands have demonstrated their desire to undertake emission reduction efforts, including aggressive pledges for clean energy supplies. Since at least the Rio de Janeiro summit in 1992, the United Nations has recognized the unique circumstances and concerns for islands in environmental affairs[10]. In the subsequent years following Rio, a number of government bodies and organizations have established programs to support renewable energy development on islands. Those include a variety of clean energy declarations by individual islands or island regions, such as the Canary Islands of Spain in 1998 and the Azores Islands in 2000.[11] Specific targets for renewable energy have followed on earlier declarations, including the Azores' goal of 75% renewable electricity by 2018.[12]

Energy security

Where climate change concerns provide limited incentive to act, oil dependency presents immediate costs to islands. Given their heavy reliance on diesel generators, island electricity systems are very sensitive to changes in global oil prices, subject as those prices are to significant volatility. For example, the price of fuel oil for electricity generation on the Azores doubled between 2004 and 2008, resulting in electricity cost increases and calls for fuel diversification.[13, 14] Even when prices are stable, islands tend to pay a significantly higher price for oil than global market rates due to their remote locations and limited bargaining power—two to three times higher in some cases.[15] This results in many island nations incurring a significant trade imbalance due to fuel imports overshadowing their limited export economies.[15] Given this lack of diversification and the high costs and risks of price shocks associated with oil dependence, island electricity systems exhibit major economic inefficiencies.[16]

It might be surprising, then, that islands persist in their reliance on oil to fuel their power systems and other energy needs despite the availability of alternative technologies. Even when new power plants are built, either for initial electrification on less-developed islands or to meet growing demands on established networks, there is a tendency to construct diesel and fuel oil plants. Some of this can be understood through the limited familiarity of network planners with alternative options, as well as the operational challenges that renewables will introduce. In addition, investment decisions often focus on up-front capital costs of new generators, with limited to no attention given to ongoing fuel and environmental costs in the future. As alternative clean energy technologies develop and costs decline, however, there is growing evidence that renewable generation—in many cases coupled with energy storage systems—offers a lower cost and less risky electricity supply option.[1, 17, 18]

2.2 Island electricity systems

Electricity grids are elaborate engineering systems involving major financial investment in infrastructure that operates over decades-long time horizons. Although they all share important fundamental characteristics, no two power systems are identical due to each system's particular portfolio of generation sources and the unique network design of transmission and distribution lines. Furthermore, each power system operates within a distinct social and economic context, with particular types and patterns of energy end-use, endowment of resources, and connections to external systems and economies. Due to smaller network sizes without the economies of scale enjoyed by large systems, the unique nature of each system is perhaps more acute for island power systems than for large mainland grids. This results in distinct challenges for optimizing network design on each island.

In order to provide an understanding of the grid and to allow an examination of where changes might occur on island systems, it is useful to consider the case of large mainland power systems in comparison. This comparison serves two purposes: 1) to point out where similarities and differences exist between these two classes of power systems and 2) to demonstrate ways in which islands have, in important respects, been the recipients of technologies and design features that developed on large systems then were "exported" to islands for adoption. Existing power system technologies and network designs developed over more than one hundred years, mainly for the needs of large mainland networks where the majority of electricity is produced and consumed. In the course of that development, fossil fuel energy sources emerged as the dominant electric fuel source, as well as large-scale centralized nuclear and hydro power plants in some regions. In more recent decades as islands built their own electricity networks, in most cases they adopted similar technologies and network configurations as already established on mainland grids. Through this lens, islands' dominant reliance on conventional thermal power plants can be partially explained through a historical perspective, in which these technologies took hold early in the development of power systems then have benefitted from network architectures, regulatory rules, and incremental innovation that is all biased toward maintaining the legacy system.

System size

The most obvious difference between mainland power systems and those of islands is the simple matter of size, the implications of which underlie many challenges related to island grids. In the case of mainland power systems—especially the developed regions of the US and Europe—the grid has been built and extended over more than a century. What began as small, local networks serving limited urban areas have, over the years, interconnected with neighboring cities, states and countries in order to take advantage of scale effects.

Among the many advantages from scale, large networks benefit from the "law of large numbers," in which small changes in electricity demand by individual customers are aggregated over a diverse set of thousands or millions of customers, resulting in smoothing of small load perturbations into a more predictable demand profile across the network. This makes generation scheduling and dispatch more predictable and reduces strain on power plants from frequent up and down ramping. The hundreds or thousands of interconnected power plants can work in coordination with each other to precisely balance the total demand for electricity with an equal supply at every moment of the day, while maintaining critical power quality specifications for voltage control and frequency across the grid. The benefits of large numbers also applies to the availability of many power plants on mainland grids, each serving a small fraction of total energy demand. The large network of power plants allows reserve requirements—or, surplus generation capacity required to be available in light of operational uncertainties—to be spread over many power plants, therefore enabling most plants to carry a small share of the requirement and thus allow efficient electricity generation.

Islands do not enjoy these advantages due to the smaller size and load diversity of island grids. Islands have many fewer power plants—counted in single digits or by the dozens—making each individual plant more critical for reliable operation of the system. Further, fewer customers can result in more drastic and unpredictable changes in power consumption levels, resulting in increased strain on island generators and, in many cases, reduced power quality. These differences that result from the size of the respective networks mean that operators of island power systems confront a different set of planning criteria than do their counterparts on large mainland grids.[16]

Diversity of generation supply

Mainland power systems tend to include a wide variety of generation types and fuel sources, as well as generation sources matched to each region's resource endowments. Large grids benefit from the diversity of generation technologies and size of power plants, which allow different plants to serve niche needs of the system. For example, nuclear, coal and hydro plants, which have high capital costs of construction but lower fuel and operating expenses, are well-suited to serving constant baseload electricity demand at all hours of the day. Meanwhile, small "peaker" power plants (typically oil or gas fired) have comparatively low capital costs but more expensive variable operating expenses, making those plants better suited for generating in a limited number of high demand hours each day or year. Between the baseload and peaker ends of the generation spectrum, there lie a variety of intermediate plants such as large natural gas generation facilities, or biomass and geothermal plants.

The result of the large size of the system and diversity of generating technologies is to allow individual plants to provide energy and network services according to their optimal design specifications—whether that is constant baseload generation, ramping up and down to follow changing demand, occasionally turning on to serve peak demand, or providing network services of voltage stability and fast-response frequency regulation. Taken together, the whole system can perform in coordination and with each plant performing a limited function for which it is best suited. Furthermore, the large number of power plants (as well as redundant and meshed transmission networks) means that no single element is so critical that its failure should disrupt power supply because other plants and system assets are available to step in and fulfill the lost generation.

Compare this to islands, where the limited number of power plants tend to be fuel oil and diesel generators.[15, 19] Due to their small to medium size, ease of construction, as well as the established global supply chains for oil given its widespread uses for transportation and home heating, oil generators tend to be the dominant generation technology on island electricity systems. Specifically, most islands rely on internal combustion engine (ICE) generation units to produce electricity. This is a very similar technology as used in automobiles, and in fact the same ICE engines that are installed on island power systems are used in large cargo and cruise ships. ICE generators harness the power of reciprocating pistons inside an engine to rotate the electricity generating turbine, rather than steam-powered turbines that are common in mainland power plants. ICE power plants are available in modular, "turn-key" designs, and are capable of fast up and down ramping speeds. This makes ICE units particularly well-suited to island needs, where individual power plants are relied upon for everything from baseload generation to load-following and frequency regulation services. Yet, electricity generation from small ICE units is significantly more expensive than conventional sources like coal and natural gas due to the high cost of oil and their inefficient operation that results from frequent ramping and cycling of generators on and off. In addition, oil generating units on islands are often of smaller power capacity than comparable units on large systems, resulting in units that are too small to achieve economies of scale and operating efficiency.[15] Furthermore, the heavy cycling and strenuous demands placed on island generation plants leads to high operation and maintenance (O&M) costs. Finally, as discussed above, dependence on imported oil exposes islands to costly energy security challenges.

Knowledge gap

In addition to being technology and infrastructure intensive, electric power systems are also heavily knowledge and skills intensive. Their design, operation and maintenance require a large and diverse workforce, encompassing every role from the designer and manufacturer of technologies to the grid operators and utility maintenance crews. In addition, the research, political, and business organizations that support the sector rely on their own specialized methods, tools, and expertise. Larger systems have a distinct advantage in this respect due to the opportunity for job specialization, as well as the potential for significant profit opportunities from deploying new technologies or energy services into such a large market. Large systems also benefit from major government agencies, industry organizations, and research centers that undertake the work of long-term planning and system design.

Islands, on the other hand, have a smaller pool of engineers and other human capital to draw upon for this type of long-term strategic thinking.[15] Instead, island grids are often managed by a few individuals at small state-operated utilities, which cannot draw upon the broader breadth of expertise available at a large utility. In these organizations, staff are frequently spread across many responsibilities and, consequently, have limited time for exhaustive investigations of strategic network planning. Furthermore, when electricity demand grows rapidly and needs are pressing, immediate concerns can lead to investment decisions with a greater short-term focus that favor familiar technologies with lower upfront costs. This will often lead to capacity expansion that relies on fossil fuel power plants such as ICE units, despite the high recurring fuel costs of these units.

Renewable energy integration

Conventional generation technologies dominate large power systems, however renewable energy sources like wind and solar have been added to many systems in recent years. These alternative energy sources hold promise for de-carbonization of the electricity supply, however many are not cost-competitive at present. Wind and solar also pose operational challenges such as variable generation from fluctuations in wind speeds and solar irradiance. At low penetrations, integration is relatively easy because generation can be spread over large regions so that variability tends to be dampened as weather patterns vary across regions. More importantly, large systems are able to support this variability given the operational flexibility provided by other controllable generators (especially natural gas and hydro). With higher levels of variable generation, the value of flexibility on power systems will increase, and new technologies and operational techniques will be needed.[20]

Islands face the same challenges with respect to renewable energy, although the challenges are confronted on different terms. Integration of variable generation can be more difficult for islands due to greater strains in maintaining supply and demand balance with a limited number of backup generating units. Furthermore, electricity demand is more variable on islands than larger systems and renewable generation does not benefit from smoothing over wide areas. As renewable generation capacity increases, this can result in periods when available generation exceeds total demand—such as during off-peak overnight periods—while other periods might have limited renewable generation due to shifting weather patterns. For example, in scenarios of high wind penetration to meet aggressive clean energy targets, there will be large swings in available wind power between different hours and seasons of the year, meaning that displacement of existing generation sources might be limited.

At even fairly low penetrations of wind and solar capacity, islands will need additional load balancing services such as those available from fast-ramping generators. Existing ICE generators are capable of providing this service on most islands, although at the expense of even more on/off cycling than those units already perform. Energy storage provides an alternative technology solution for integration of renewables, which has been the subject of great interest for island power systems. Most storage technologies are in early stages of development, however, with high costs and unproven performance. Nonetheless, studies have shown that wind and solar generation coupled with available storage technologies may already be lower cost than oil-fueled electricity for some islands.[1, 2, 21]

On a total cost basis, islands might be better positioned for adoption of renewables than large power systems. Due to reliance on expensive oil imports and the resulting high costs of electricity on islands, renewable energy becomes competitive at a higher cost on islands than it does on mainland systems. This creates a potential for islands to be early adopters of alternative technologies, when costs remain out of reach for other systems.

Legacy versus optimal system design

As this discussion suggests, modern electric power systems are the result of technologies, design choices and investments made many years in the past. While decisions were mostly made for good reasons at each turn, the system that has resulted does not reflect optimal design and performance criteria in light of today's scientific knowledge, available technologies, and environmental concerns. This is most true on large mainland networks, where centralized fossil fuel generators took hold in early years, then further development has entrenched these designs. As Arthur has described the phenomenon, this is an example of a path-dependent outcome based on historical rather than optimal conditions, resulting in "technological lock-in" from which it is difficult to subsequently escape.[22] Islands have been on the receiving end of these forces, given their status as technology-takers and their limited resources for developing knowledge and skills that might result in a better structure. Although many island grids are relatively new—having been constructed in the second half of the last century and, in some developing islands, remain incomplete—those systems have not necessarily benefited from their late entry. Rather, generation technologies and conventional wisdom regarding operating protocols were adopted from large network designs and forced to fit in the island context. Despite the possibility for alternative system designs and energy sources, islands have been the recipients of energy systems better suited for a different setting.

Chapter 3

Policy context

Given the strong case for renewable energy on islands, including cost-competitiveness, heightened interests in reducing GHG emissions, and reduced dependency on oil imports, why is greater investment in renewables not undertaken? An answer is provided, in part, by what Gregory Unruh has described as "carbon lock-in".[23] Carbon lock-in suggests that the power system in its many technical as well as institutional dimensions is biased toward carbon-based energy sources, making it difficult to transition onto another paradigm. Policy tools are needed to overcome the forces of carbon lock-in[24], however this is especially difficult in electric power systems due to the deeply entrenched and overlapping political jurisdictions and reliability standards that govern the system. Those include regional, national, and supra-national political bodies that dictate desired policy objectives for energy, as well as utility or industry-wide operating procedures for the purpose of maintaining reliable electricity supply. Islands are subject to a similar overlapping policy context as larger mainland systems, yet at the same time islands tend to be overlooked in major policy development.

This chapter provides a discussion of the forces of carbon lock-in as they apply to islands, followed by discussion of the policy context within which island power systems exist. Attention is focussed on high level energy policy in the European Union and general reliability criteria that is central to all electric power systems, followed by brief discussion of available tools to address island energy challenges.

3.1 Carbon lock-in on islands

Conventional economic theory suggests that market failures underly the challenge of investment and development in clean energy. Relevant market failures include bounded rationality, information asymmetries, moral hazard and principal-agent problems.[25]

In an analysis focused on energy efficiency investments in the United States, but with fundamental insights that are broadly applicable to clean energy adoption everywhere, Brown identifies a set of market failures that fall within this standard economic perspective: 1) Misplaced incentives, 2) Distortionary fiscal and regulatory policies, 3) Unpriced costs and benefits, and 4) Insufficient and inaccurate information.[26] Among Brown's market failures, two are particularly relevant in the context of island systems: unpriced costs and benefits (i.e. externalities), and imperfect information. As discussed in Section 2.1, islands are on the losing end of the most significant externality associated with fossil fuel energy—that is, climate change—while at the same time suffer from imperfect information in the form of a shortage of human resources and expertise for energy system planning.

In addition to these market failures, Brown defines market *barriers* as "obstacles that are not based on market failures but which nonetheless contribute to the slow diffusion and adoption" of innovations, and identifies barriers relating to "low priority of energy issues", "capital market barriers", and "incomplete markets" for alternative energy services.[26] Of Brown's barriers, capital market barriers are most relevant to clean energy investment on islands, given limited budgets available for upfront investment in renewable energy technologies and short-term financial criteria that underweight fuel costs incurred in the future.

While these explanations provide important insights, they are primarily directed at microeconomic firm-level and individual decision-making, with less insight to centrally designed and state-operated systems[23]—which is the structure for most island energy systems. A more complete answer appears to lie in a variety of structural and institutional forces that impose their own barriers to adoption of clean energy technologies. Specifically, the incumbent status of traditional fossil fuel technologies function as a kind of technological lock-in that privileges conventional generation sources on power systems. Unruh describes this situation as "*carbon* lock-in" (emphasis added), arguing that "industrial economies have been locked into fossil fuel-based energy systems through a process of technological and institutional co-evolution driven by path-dependent increasing returns to scale."[23] That evolution occurred without full awareness of the environmental costs associated with fossil fuel energy consumption; now that lock-in has taken hold, however, the barriers to change are greater than they would be if a different path had been taken.

Notably in the case of islands, the historical and technological pathway that led to the current situation was largely a result of factors on larger, mainland energy systems. While these dominant generation technologies have turned out to cause serious negative externalities worldwide, they might be even less well-suited to islands. Especially where islands are dependent on high-cost oil-burning generators and are subject to oil price fluctuations on global markets, a strong case can be made for the advantages of locally sourced generation—wind, solar, ocean currents, and geothermal or hydro-generation where available. Yet, even where new generation capacity is needed to meet future demand, island system planners often choose to add additional oil and other conventional power sources. This is explained by a variety of reasons, including network effects in which system operators prefer proven technologies that they are familiar with and for which operation and maintenance procedures are similar to existing generators.[15]

3.2 EU climate and energy policy

The European Union has actively promoted policy in the last two decades to address climate change through the reduction of greenhouse gas emissions. EU policy is oriented toward the three-fold "20-20-20" targets to achieve by the year 2020: 1) 20% reductions in greenhouse gas emissions below 1990 levels, 2) 20% of energy consumption derived from renewable resources, and 3) 20% improvement in energy efficiency. Long-term policy is aimed at major emissions reductions of 80–95% by 2050.

In concert with clean energy policy, the EU is undertaking a comprehensive reform process to integrate national and regional electricity markets across the continent into a single EU "internal energy market". Two primary objectives of the process are to integrate large amounts of renewable energy resources and to encourage market competition, in part by eliminating state interventions that are seen to distort markets. Significant progress has been made on these fronts, however the reform process has confronted challenges with how to integrate historically separate systems in the face of competing national energy policies and anti-competitive measures in many localities.

At present, EU energy policy is codified under the 2009 Directive (2009/28/EC), which states in part: "Member States shall take appropriate steps to develop transmission and distribution grid infrastructure, intelligent networks, storage facilities and the electricity system, in order to allow the secure operation of the electricity system as it accommodates the further development of electricity production from renewable energy sources."[27] In an attempt to address economic differences between countries, the 2009 Directive includes terms for a "solidarity mechanism" to help less affluent countries transition to a low-carbon economy. The solidarity mechanism grants Portugal 12% greater emissions permits than its historical share in EU emissions, thus offering the possibility for generating revenues from selling the allowances if unused.[28]

In principle, EU requirements apply to island regions the same as the mainland, however in practice it is difficult to introduce meaningful competition on small island systems. In cases where islands are physically separated from larger electricity grids due to lack of interconnections and their small market size serves as a barrier to attracting investment and ownership by competing power producers, small islands will likely remain under the effective control of a single vertically integrated utility.[29]

3.3 Power system reliability criteria

Many island grids do not meet basic reliability criteria that is standard protocol for electric power systems. This is especially true for the smallest networks (those less than 15 MW peak load).[30] Due to the small number of generating units and under-built networks in some cases, islands tend to experience more frequent power outages and a large number of island systems do not meet N-1 criteria.[1] Where islands do have adequate installed capacity—more common for developed regions such as the Azores—the opposite problem is encountered: due to their small size and reliance on a limited set of power plants that each account for a relatively large share of total system capacity, some island power systems are overbuilt and have generating units that sit idle most of the year.

This section provides some background on power system reliability criteria—commonly referred to as security of supply—and the common approaches for maintaining adequate reliability. Attention is devoted to reserve requirements on islands, because this is the main tool for ensuring power system reliability and it tends to be a key factor in system planning and resulting costs.

3.3.1 Security of supply on power systems

As a simplified but useful approximation, the technical objective of the electric power system—including all the generation, transmission, and other assets that it encompasses, as well as people and institutional structures behind the physical system—is

[1] That is, the loss of the largest system asset to network contingencies—either a generating unit or transmission line—might result in non-served energy because the remaining system is unable to make up the capacity shortfall.

to provide an adequate quantity of power to precisely serve total demand. Furthermore, that quantity of power must be delivered at precisely the time and location that it is demanded. Any violation of that objective will result in some combination of non-served energy (blackouts) or violation of power quality criteria that can be damaging to both grid infrastructure and consumers' electronic devices. In reality, there are operating tolerances within which supply and demand levels can be slightly off, but those tolerances are so relatively small as to be negligible. On systems where tolerances are frequently violated, as is common in developing countries, power quality is low and blackouts are common—with devastating implications for economic growth and quality of life.

In order to achieve supply-demand balance in practice, the problem is de-coupled into various time dimensions to facilitate planning and operation of the system. The regulatory and institutional frameworks that have developed for nearly every power system in the world are, in large part, designed to achieve satisfactory levels of security of supply. As described by Rodilla, "The intervention of the regulator is needed to guarantee a minimum required level of security of supply in different places and timescales, since it has been largely demonstrated that otherwise they will not occur."[31]

One standard approach, as defined by the North American Electric Reliability Council (NERC), is a simple two-dimensional classification into *security* for short-term load-balancing and *adequacy* for long-term capacity planning.[32] Batlle et al expand that classification to four time-dimensions, more accurately reflecting the nature of modern grid operations and considerations that must be made in each of multiple overlapping time horizons. As defined by Batlle et al[33], those are:

1. **Security** (short-term, close to real-time) – "The readiness of existing generation capacity to respond, when it is needed in operation, to meet the actual load... Security typically depends on the operating reserves that are prescribed by the System Operator."

2. **Firmness** (short to medium-term) – "The short-term generation availability that partly results from operation planning activities of the already installed capacity... Firmness depends on short and medium-term management of generator maintenance, fuel supply contracts, reservoir management, start-up schedules, etc."

3. **Adequacy** (long-term) – "The existence of enough available capacity, both installed and/or expected, to meet demand."

4. **Strategic expansion planning** (very long-term) – "The concern for the long-term availability of energy resources: physical existence, price, energy dependence of the country, reliability of the internal and external energy resources, potential environmental constraints, etc."

Regulatory and policy measures are needed for maintaining all four, and in some cases attention to one dimension can lead to new challenges for another. For example, introduction of renewable resources is aimed at the fourth dimension: strategic expansion planning to achieve economic and environmental goals. But intermittency of renewable resources leads, in turn, to challenges to the first and second dimensions of short to medium-term supply balancing.

Power systems everywhere are investigating new requirements and undertaking reforms to manage security of supply challenges. For example, through more robust ancillary service markets and remuneration schemes (security) and capacity markets or other long-term contracts for reliability (adequacy). Those are market-oriented approaches, however, which assume competitive market structures and large networks with many competing asset owners and stakeholders. That is not the situation on most islands, where single utilities are responsible for owning, operating, and planning the system. In this situation, it might be more appropriate to adhere to defined engineering standards—imposed by a government regulator if necessary—that will ensure the reliable operation of the system.[29] In fact, it is those engineering standards that competitive markets attempt to mimic in many cases, and for which markets rely on various regulations in order to force compliance.

3.3.2 Reserve requirements

Power systems have for many years relied upon over-provision of generation capacity in order to ensure that security of supply is maintained. This additional capacity comes in many different forms and under a variety of names, but is generally captured under the umbrella term "reserves". Reserves are procured at a sufficient level above expected load to guard against uncertainty for actual load levels and for supply-side contingencies. In most systems there are two general categories of reserves: capacity reserves and operating reserves.

Capacity Reserves

Capacity reserves refer to the level of installed capacity on a power system, and are typically measured in reference to peak demand on a given system. These reserves are a long-term consideration, by which electricity system planners look out years into the future and estimate how much installed capacity will be required to serve expected load growth. Historically on conventional power systems, vertically integrated utilities have been responsible for long-term planning and had to satisfy government regulators with their capacity investment plans. In recent years, as power systems have undergone deregulation and generation capacity was divested from single monopoly utilities, capacity markets and other means of "regulated competition" have developed for the purpose of maintaining long-term capacity reserves at efficient cost. Whatever the market structure, large power systems tend to require capacity reserves on the order of 10–20% of total peak demand. Islands, on the other hand, might not have defined criteria for capacity reserves, and systems range from those with inadequate installed capacity to others that have reserve levels of 100% or greater.[30]

Operating Reserves

Where capacity reserves are for purposes of long-term supply adequacy, operating reserves ensure that supply is available to meet demand in timeframes of hours to seconds. Milligan et al define operating reserves as "the real power capability that can be given or taken in the operating timeframe to assist in generation and load balance and frequency control."[34] Every region and energy system uses different naming conventions and specific standards for determining operating reserve levels. In general, systems require some amount of "spinning" reserve—or available generation capacity from units that are online and able to respond to generation shortfalls in a matter of seconds or minutes—and possibly additional "non-spinning" reserve from fast-start generators that can be brought online in 30 minutes to an hour.

As penetration of variable-output wind generation increases on many power systems, operating reserves are becoming more critical and the specific needs and required quantities for reserves are changing. The determination of reserve requirements has significant implications for the amount of wind that can be reliably installed and for the costs associated with wind generation, however there is currently no consensus approach for how to best determine reserve requirements on high wind power systems.[3] Even less attention has been devoted to reserve requirements on island power systems, although at least one study concludes that reserve requirements on islands need to undergo significant revision—and flexible generation capacity should be added—to avoid spilling large amounts of wind generation.[4]

3.4 Policy options

The overlapping challenges of climate change, energy security, and carbon lock-in demand major policy attention and strategic planning for island power systems. Where energy security provides the most compelling basis for transitioning away from oil-dominated power generation, carbon lock-in suggests that such a transition is unlikely to occur given the existing economic and institutional forces on islands. In this situation, policy tools are needed to overcome entrenched paradigms.[24] This section discusses three broad areas where policy attention is needed.

Matching technologies to island needs

In recent years, the technology mismatch between available generation technologies and the operating circumstances on small isolated electricity networks has diminished. The emergence of cost-competitive wind and solar technology means that islands have more options for electricity generation than the traditional ICE power plants. While not as technically viable or cost-competitive yet, other renewable energy designs such as wave and tidal generation systems offer promise as well. This is a significant shift in the technology landscape, creating potential for islands to transform their generation portfolios from a reliance on imported fuel to tailoring their systems to reflect local resources and needs.

In addition to adding centralized renewable generation capacity, islands would benefit from careful planning for other system design considerations. Although many island networks are well developed, with central power stations already built and the transmission network laid, there remains an opportunity for redesign or expansion of networks to accommodate distributed generation such as rooftop solar. Network design can also incorporate advanced metering infrastructure and controls that will enable "smart grid" development for more efficient utilization of energy resources. Demand response and energy efficiency programs have the potential to significantly alter load levels and consumption patterns in order to match demand to available energy supply.

Finally, energy storage can provide valuable grid services for power quality and integration of renewables. Where islands suffer from greater uncertainty and variability in load patterns due to their small size, fast-response storage can smooth supply-demand mismatches that arise. Furthermore, bulk energy storage can balance the hourly, daily and seasonal variations in renewable resource availability by shifting energy from those periods when renewable energy is abundant to later periods when it is not. While energy storage is cost-prohibitive for many power system applications, that cost barrier tends to be less restrictive on islands due to the higher cost that islands' pay for electricity.

Financing mechanisms

While the technology options have improved, high capital costs remain a barrier to investment in clean energy technologies. Even in cases where lifetime levelized costs of electricity are less for renewable resources than fuel-burning generators—due to the zero cost of fuel for wind and other renewables—upfront investment in renewable power plants can be cost-prohibitive. The higher capital cost of renewables results in longer payback periods required for clean energy options than conventional generation—time horizons that cash-strapped island utilities often do not account for in immediate investment decisions. Thus, financial support is needed to help grid operators invest in clean energy.

Financial support for energy infrastructure has typically come in the form of subsidies and investment credits for clean energy projects, or technology transfer mechanisms in which other nations or jurisdictions support clean energy investments in less-developed regions.[35] These are useful policy tools which could be applied more widely to island systems. In Europe, the European Investment Bank (EIB) is also an avenue for dispersing loans for critical infrastructure projects, such as a recent 65 million euro loan to the Azores electric utility for upgrades to generation and transmission projects.[36]

In light of the opportunity for islands to be proving grounds for new generation technologies and system designs, the case for financial support from abroad does not rest strictly on reasons of charity. Mainland governments, utilities, and technology vendors stand to benefit from technology improvements and lessons learned as a result of the experience on islands. In this way, there is a a potentially lucrative partnership between island and mainland stakeholders around energy system investments.

Island associations and knowledge pooling

The knowledge gap faced by islands is a significant challenge to adoption of clean energy systems.[15] Island grid operators have limited time to undertake planning studies for long-term system design due to staffing shortages and limited exposure to alternatives. Futhermore, utility employees on islands are often generalists rather than specialists with the narrowly-defined expertise that can be found in larger utilities. This is appropriate for smaller systems with limited financial resources, and will produce highly capable and resourceful staffs in many cases. Regardless, small staffs are not be able to perform all the roles of a larger company and must instead rely on familiar technologies and procedures. Frequently, this will lead to capacity expansion and other investments that perpetuates the existing system design, for example by adding fuel-burning ICE generators.

To overcome this, islands have begun to pool resources and expertise with one another, creating knowledge networks as well as bringing greater attention to their concerns. For example, the EU "Pact of Islands" (or Isle-Pact) has been signed by 64 island communities, of which 56 have written "Sustainable Energy Action Plans".[37] Isle-Pact is also actively involved in policy development discussions at the European Parliament and it seeks to develop and share software and planning methods for further clean energy development on islands. The European electricity industry body, EurElectric, has also taken an active interest in island power system planning, including the ongoing work of the EurElectric "Network of Experts on Islands" and semi-regular workshops convened for island power system interests.[38] Fewer island resources exist outside of Europe; one exception being the Small Islands Developing States Network (or SIDSnet) for advocacy and resource pooling on behalf of less-developed island nations.[39] These efforts are nascent and under-resourced, however, leaving potential for significantly more coordination among islands around the world.

Chapter 4

Energy storage overview

Given the operational challenges encountered on island power systems, including greater variability in demand as well supply-demand balancing problems introduced by intermittent renewables, new technologies and operating procedures are needed. Energy storage offers one possible solution. Storage can absorb surplus energy during periods when available generation exceeds demand, then release that energy back onto the grid in later periods. In some cases, energy storage is also capable of short-term charging and discharging—on the order of seconds or minutes—in order to smooth frequency perturbations on the grid and reduce up and down ramping or on/off cycling of generation units. In this manner, energy storage can enable higher penetrations of renewable generation and possibly improve the economics of power systems.

This chapter describes energy storage for electricity system applications in further detail. General discussion is followed by focussed attention to the applications and technologies that are most relevant to island power systems, as well as the key parameters of the modeling performed for this research.

4.1 Performance and uses of energy storage

The Electricity Storage Association (ESA) identifies three "functional categories" for storage—Power Quality, Bridging Power, and Energy Management—distinguished by the duration over which the storage device operates. As described by ESA[40]:

1. **Power Quality.** "Stored energy is only applied for seconds or less, as needed, to assure continuity of quality power."

2. **Bridging Power.** "Stored energy is used for seconds to minutes to assure continuity of service when switching from one source of energy generation to

another."

3. **Energy Management.** "Stored energy is used to decouple the timing of generation and consumption of electric energy. A typical application is load leveling, which involves the charging of storage when energy cost is low and utilization as needed. This would also enable consumers to be grid-independent for many hours."

While these categories provide a good starting point, in reality the services available from energy storage are often difficult to differentiate into clearly separable services. In addition, duration of storage service is only one measure of storage performance, which in fact is a second-order attribute of storage performance, itself derived from attributes for power and energy.

Similar to power plants, energy storage devices can be classified according to the power capacity at which they are able to send energy to the grid. Power capacity is measured in units of power (e.g. kilowatts or megawatts), and every storage devise has a maximum power level at which it is able to discharge energy to the grid. Notably for storage, power capacity is also important for charging because it determines the rate at which the storage devise is able to absorb energy from the grid to replenish stored energy. The maximum rate of charging will not necessarily be the same as the rate of discharge.

In addition to power capacity, *energy* capacity is also a critical dimension of storage technologies' potential value and performance. Every storage system has a maximum amount of energy that it is able to hold (measured in units of kilowatt-hours or megawatt-hours), and this energy capacity will partly determine the types of services that it can provide. For many storage technologies, there is also a minimum energy capacity to which the system can be depleted before operating performance or product lifetime is compromised. The minimum might be imposed as an operational restriction to prevent "deep discharge" that would damage the performance of the device (especially true for battery storage), or a relative restriction where power potential declines as stored energy declines (such as for the amount of water stored behind a hydro dam).

Taken together, the power and energy capacity of a storage system results in a maximum duration at which the system is able to discharge energy at full power when starting from maximum energy capacity. That duration can be important to power system operation, because it limits the time over which storage can be relied upon to provide power to the grid before it is depleted and other generation sources are needed. Of course, the duration will be longer if a storage device is discharged at less than full power.

Among the many grid services that are proposed for storage, commonly cited applications include bulk energy storage for seasonal energy management or peak shaving, ramping and load following for balancing renewables, provision of spinning reserves to displace conventional generation capacity, and frequency regulation. Each of these services require different operating specifications from the storage device, mainly along parameters for rate of response and power capacity. Figure 4-1 (adopted from work by the Electric Power Research Institute [41]) shows how different services from storage relate according to dimensions of total power and time of response.

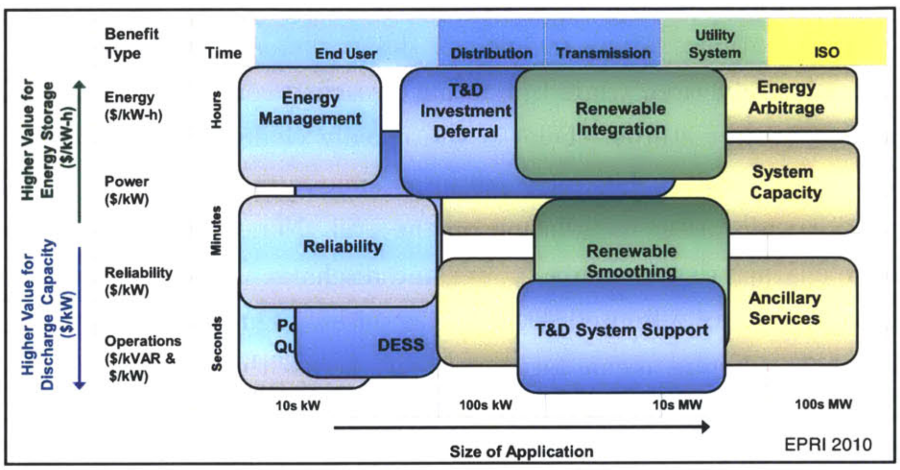


Figure 4-1: Grid services from energy storage

Another performance dimension of energy storage technologies is their efficiency, or energy losses resulting from charging and discharging. All storage systems incur some amount of energy loss through the round-trip storage cycle, due to energy requirements for the charging or discharging process itself or from inefficiencies in the physical or chemical properties of the storage medium. These energy losses impose an important consideration for when it makes sense to store and release energy, because the economic gain in shifting energy across time must be greater than the costs resulting from lost energy. On most storage systems available or under development, roundtrip efficiency is in the range of 60–95%, where higher efficiencies will tend to result in higher value and more applications for storage.

In the case of islands, all grid services shown in Figure 4-1 are potentially valuable depending on island conditions and network designs, and the best uses of storage will depend on the particular circumstances of each island network. In some cases, more than one storage service—such as system capacity from bulk energy storage plus energy management from fast-response storage—may be desirable and could be separately provided from different storage installations. Due to the small system size of island power systems, however, the appropriate size of applications along the bottom axis (shown in kW and MW) might be scaled down somewhat for each respective network service.

4.2 Description of storage technology options

Dozens of energy storage technologies are proposed and under development for electricity grid applications. Many technology designs remain in research and development stages of production, while others have reached commercialization or at least demonstration-project status. Due to the rapidly changing nature of the storage technology landscape, it is difficult if not impossible to predict which technologies are best suited for widespread installation on the grid. Nonetheless, based on expected performance characteristics such as power and discharge rate, candidate technologies are often considered for a limited set of grid services. Figure 4-2 (adopted from EPRI [41]) shows how different technologies compare across the dimensions illustrated in Figure 4-1.

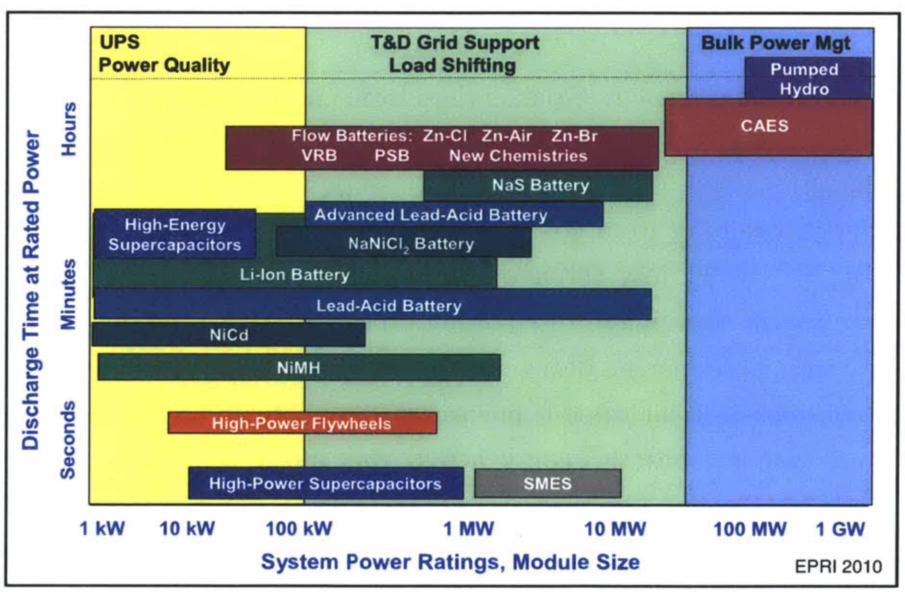


Figure 4-2: Comparison of energy storage technology performance

Table 4.1 is adapted from EPRI[41] and shows how some of the leading technologies compare across key dimensions. The table includes technologies at a range of maturity levels, making operating performance more uncertain for those technologies that have not yet been widely deployed. Costs listed in this table are aspirational for many early-stage technologies; in some cases, achieving the costs shown here would represent a dramatic improvement in the economic basis for energy storage.

Technology	Capacity (MWh)	Power (MW)	Duration (Hrs)	Cycle Efficiency	Total Cost ($/kW)
Bulk Energy Storage to Support System and Renewables Integration					
Pumped Hydro	1680–5300	280–530	6–10	80–82%	2500–5300
CAES (underground)	1080	135	8	–	1000
Sodium Sulfur (NaS)	300	50	6	75%	3100–3300
Advanced Lead-Acid	200	50	4	85–90%	1700–1900
Energy Storage for Utility T&D Grid Applications					
A-CAES (aboveground)	250	50	5	–	1950–2100
Sodium Sulfur (NaS)	7	1	7	75%	3200–4000
Advanced Lead-Acid	3–48	1–12	3–4	75–90%	2000–4600
Lithium-Ion	4–24	1–10	2–4	90–94%	1800–4100
Energy Storage for Fast Frequency Regulation and Renewables Integration					
Flywheel	5	20	0.25	85–87%	1950–2200
Lithium-Ion	0.25–25	1–100	0.25–1	87–92%	1085–1550
Energy Storage for Commercial and Industrial Applications					
Advanced Lead-Acid	0.1–10	0.2–1	4–10	75–90%	2800–4600
Lithium-Ion	0.1–0.8	0.05–0.2	2–4	80–93%	3000–4400

Table 4.1: Performance and cost of energy storage technologies

Brief overviews of some energy storage technologies—selected for those most relevant for island applications—follow in the sections below. Detailed technical descriptions and additional technologies are well-documented in other research, including Kaldellis et al (2009), EPRI (2010), Bradbury (2010) and Hadjipaschalis et al (2009).[1, 41, 42, 43]

Pumped hydro

The oldest and most widely used form of energy storage on electric power systems is pumped hydro. Pumped hydro harnesses the power of water falling from a raised reservoir to a lower reservoir in order to turn a turbine and generate power in the same manner as conventional hydro power systems. The difference is that flow can be reversed in order to move water uphill to the upper reservoir in low-demand or low-cost periods in order to store the water as potential energy for generation at a later time. Pumped hydro is well-suited for bulk power management applications, including on-peak/off-peak arbitrage and providing additional system capacity. The advantages of pumped hydro include its mature state of technical development and relatively low cost, however costs and availability depend on the geographic suitability of sites. Pumped hydro is an attractive option for islands, including for managing supply and demand mismatches that result from renewable integration, however its potential is limited by geographic constraints. Most small islands do not have appropriate land available for pumped hydro, including land with necessary elevation for both upper and lower reservoirs.

Compressed air energy storage

Compressed air energy storage, or CAES, is an alternative energy storage design that can be used for similar applications as pumped hydro. CAES technology is relatively mature, although the number of operational CAES systems in the world remains limited. In conventional CAES systems, electricity is used to compress air to high pressures in a closed chamber, typically in large underground caverns such as those formed by salt caves. The compressed air is released later and heated by burning natural gas to power a combustion turbine similar to oil- or gas-fired combustion turbines. In this way, CAES systems are different than other energy storage technologies because they effectively harness the power of compressed air to operate a highly efficient gas turbine. Therefore, CAES storage systems do not have an efficiency in the same sense as other storage technologies, but rather a very low heat rate as compared to other generation options—under 4,000 Btu/kWh for underground CAES systems.[41] CAES can be a highly cost-effective storage option, however its application on islands will be limited by geographic constraints for available underground caverns, and the need for gas imports to support energy conversion.

Alternative CAES designs are under development that would not require underground storage nor gas combustion. Aboveground "adiabatic" CAES systems (A-CAES) would use heat from thermal power captured during compression of air into pipes or other vessels to heat the released air at time of discharge, thereby significantly reducing or eliminating the reliance on fuels or external power during energy discharge. Current aboveground CAES designs are relatively large, however smaller modular sizes should be available with time, which could find application on island power systems. At this time, A-CAES is an emerging technology that is yet to be deployed beyond small demonstration projects so future costs and performance are highly uncertain.[44]

Battery storage

Electric batteries hold great promise for potential applications on island power systems. Although batteries have been around for many years, their use has been limited by high costs, short lifetimes, and high energy losses in roundtrip charging and discharging. This is changing, however, as ongoing developments in chemical compositions and technical designs hold promise that batteries can be an effective grid-scale energy storage device. Indeed, battery demonstration projects are being deployed across the world—on large mainland grids as well as islands—that should lead to further advances in design and commercialization of the best battery technologies.

Among the advantages of batteries, they do not require particular geologic formations and can be produced in modular systems, allowing battery projects to be scaled according to local needs. This is particularly useful for islands, where the diversity of island systems will require a range of storage sizes. In addition, battery installations are relatively small—requiring less than a single shipping cargo container in some cases—making them easy to site at locations with existing grid infrastructure such as substations or power plants. Many battery designs are also able to charge and discharge relatively quickly, making them well suited for renewable integration where intermittent generation introduces greater variability on the grid.

As an emerging technology, however, batteries also have some shortcomings that are barriers to more widespread deployment. For one, the capital cost of battery systems remains high. Until economies of scale are captured from high-volume manufacturing, the average cost of each new battery installation is often above levels that would justify investment compared to other grid investments. In addition, the roundtrip efficiency of some battery systems is low compared to other storage options, and batteries suffer from performance degradation over their lifetime as chemicals and materials deteriorate from operation. There is also a serious investment risk from emerging battery technologies, as performance quality under actual operating conditions will not be known until after more widespread deployment. In a handful of recent cases, there has even been catastrophic failure of battery systems where battery banks overheat and ignite. For example, in August 2012 on the Hawaiian island of Oahu, a 15 MW battery storage facility caught fire and destroyed millions of dollars of batteries and related hardware.[45]

Batteries are available or under development in a wide diversity of designs. One leading design that is commercially available are sodium-sulfur (NaS) batteries. NaS batteries offer a stable chemical composition, with relatively long useful lifetimes and adequate efficiency, and require minimal installation space.[18] More than 300 MW of NaS batteries have been installed at over 200 sites worldwide.[41] Other battery technologies remain under development but hold promise for higher efficiencies and higher power ratings. Advanced designs for lead-acid batteries are proposed for grid services ranging from medium- and fast-response power quality to bulk energy load shifting. Lithium-ion batteries have also been proposed for high-power reliability services and can achieve very high operating efficiencies.

Flywheels

Flywheels provide rapid response energy on the timescale of seconds and are well-suited to power quality service for frequency regulation. While they offer very fast response, they are energy capacity limited and therefore cannot be used for the long durations that are required to provide on-peak/off-peak load shifting. Given the challenges of highly variable load changes on small islands—exacerbated by intermittent renewables—flywheels are particularly well-suited to the needs of small island grids. In fact, flywheels have been installed on a handful of islands, including two in the Azores.

4.3 Market development for energy storage

While total installations of energy storage remains small, limited mainly to pumped hydro systems, storage might be staged for significant growth. As recent advances in material science and designs are tested and developed further, the costs and performance of storage systems will improve. Technology development has been further helped in recent years by a rise in research interest and government support, including large investments by the US government under the American Recovery and Reinvestment Act of 2009 ("the stimulus") and ongoing support from the Department of Energy's ARPA-E program. In this pursuit, the Department of Energy has established an energy storage cost target of $1,750/kW for capital investment (including balance of system costs) by 2016, and a long-term target of $1,250/kW.[46]

As storage technologies develop, early adoption is likely to occur at demonstration projects and for niche uses such as commercial applications like backup energy storage for data servers and on military bases. These installations allow "proof of concept" and the opportunity for storage developers to test and improve upon initial designs and manufacturing processes. Niche applications will also tend to offer higher value from energy storage, therefore imposing a more easily surmounted cost barrier to new technologies. Island power systems are similar in this regard, because the cost of electricity is higher than on mainland power systems, and the needs for grid balancing services are in many cases greater. Furthermore, given the small total size of island electricity systems, the impacts of storage projects can be tested at smaller installations, thus providing valuable information to inform further development of storage technologies. In this manner, island power systems offer a valuable "bridge" application for energy storage on the way to full-scale integration on larger grids.

Chapter 5

Context for study: Azores Islands

The Azores present an excellent context for island energy system research and project development because they offer nine separate islands of differing size and energy needs. Furthermore, the relative economic strength and strong institutional structures of the Azores as compared to many other island states around the world means that project development is readily feasible and utility practices can be transferrable. This chapter provides a general overview of the Azores islands, followed by a discussion of the islands' energy needs and existing electricity networks. The chapter concludes with a discussion of the three islands modeled in this research.

5.1 Islands overview

The Azores are an archipelago of nine Portuguese islands in the Atlantic Ocean about 1,500 km west of mainland Portugal with a population of 245,000. Administratively, the islands form the Autonomous Region of the Azores—one of two autonomous regions of Portugal. The islands are governed by a single regional government, with each island divided between one or more local municipalities and sub-municipality parishes.

The islands are situated atop the junction of three tectonic plates—the Eurasian Plate, the North American Plate, and the African Plate—and a number of major fault lines run through the region, including the Mid-Atlantic Ridge that runs north-south along the length of the Atlantic Ocean. All nine islands are active volcanoes, with varying degrees of volcanic activity. The islands are clustered in three major groups: the eastern group composed of two islands including the largest island of São Miguel, the central group composed of five islands, and the western group with two islands. The full archipelago stretches 600 km along a southeast-to-northwest axis.

Brief descriptions of individual islands follow in the sections below.[1]

The eastern group: São Miguel and Santa Maria

São Miguel and Santa Maria are the easternmost islands of the Azores. São Miguel is the largest island, both in terms of land area and population (approximately 750 km^2 and 140,000 people, respectively). Ponta Delgada on the southern coast is the largest city on São Miguel, with 65,000 people in the city and surrounding municipal area. Ponta Delgada is also the largest city in all of the archipelago and is the administrative capital of the Autonomous Region of the Azores. The economy of São Miguel consists of tourism, agriculture, government services, and some commercial activity. The growing tourist economy on São Miguel relies on visitors from mainland Portugal as well as international points of origin and supports many commercial and service businesses in Ponta Delgada and elsewhere on the island.

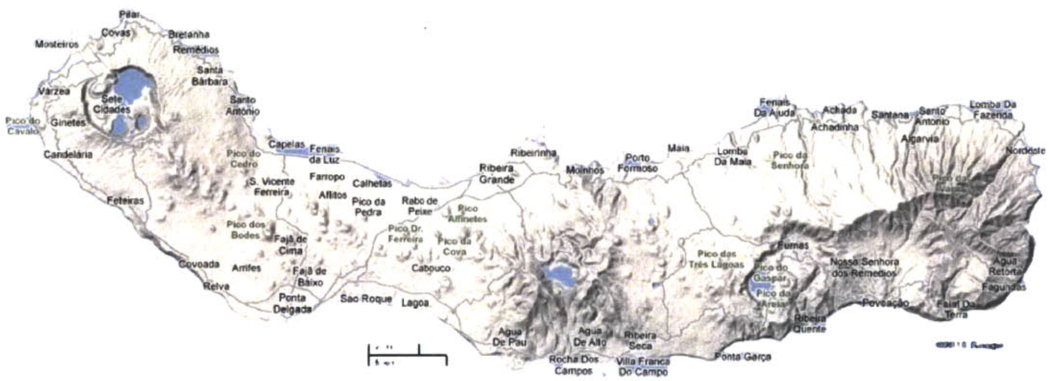


Figure 5-1: Map of São Miguel

Figure 5-2: Map of Santa Maria

Santa Maria is about 100 km south of São Miguel and is both the most southern and most eastern of all Azores islands. The population of Santa Maria is around 6,000 people, about half of whom live in the largest city of Vila do Porto. The island has a land area of almost 100 km^2. Santa Maria is a popular tourist destination on account of its white sand beaches and relative accessibility from Ponta Delgada. In addition, the Santa Maria

[1] Maps for individual islands are adapted from Google Maps.[47]

economy consists of small-scale agriculture, small artisanal industry, and fishing.

The central group: Terceira, Graciosa, São Jorge, Pico and Faial

Five islands are clustered in the center of the archipelago, about 200 km northwest of São Miguel. The largest of these is Terceira, the second largest island in the Azores. Terceira has an area of 400 km^2 and a population of 55,000 people. The population is divided between two municipalities, Angra do Heroísmo and Praia da Vitória, each with a number of towns and parishes. Terceira is home to a Portuguese Air Force base and a U.S. Air Force detachment. In addition to the military bases, Terceira's economy relies primarily on livestock and dairy-related activities, as well as some industry and trade around the island's two main harbors.

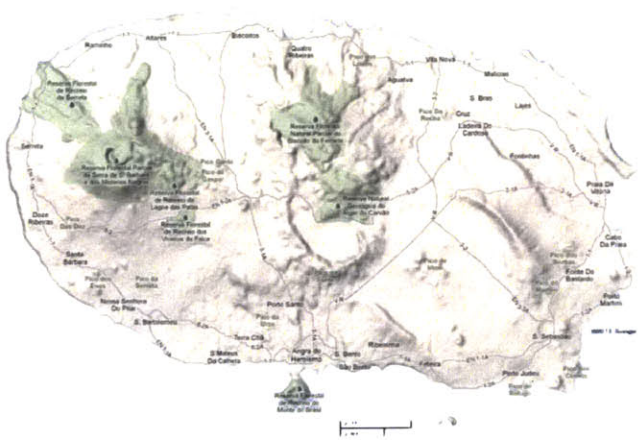


Figure 5-3: Map of Terceira

Northwest of Terceira is Graciosa, one of the smaller Azores islands. About 5,000 people live on the 60 km^2 island. Santa Cruz on the eastern coast is the largest town on Graciosa. The island economy consists mainly of small-scale agriculture, vineyards and dairy farming.

Figure 5-4: Map of Graciosa

Figure 5-5: Map of São Jorge

To the east of Terceira is São Jorge. About 10,000 people live on the island, living in two mostly rural municipalities containing 11 parishes. São Jorge is relatively large at 245 km^2, however the island is oriented along a narrow southeast-to-northwest axis, and is only 5–8 km wide along that length. São Jorge is fairly active as a volcano, having erupted at least six times between 1580 and 1907.[48] The São Jorge economy consists mainly of agriculture—including active dairy farming and cheese making activities—as well as tourism.

The island of Pico is southwest of São Jorge across a 15 km strait. With more than 15,000 inhabitants, Pico is mid-sized relative to other Azores islands and, at 450 km^2, has a relatively large land area. The island is divided between three municipalities, the largest of which is Madalena on the western coast. The dominant feature on Pico is the cone-shaped mountain rising from the southern side of the island. Ponta do Pico rises 2,351 meters (7,713 feet) above the sea and is the highest point in all Portuguese territory. The island last erupted in 1963.[48] The Pico economy is based mainly on vineyards, local winemaking, and tourism.

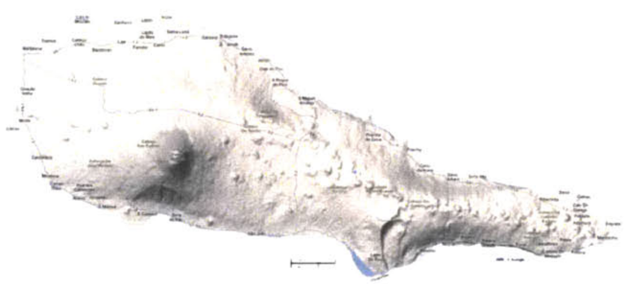


Figure 5-6: Map of Pico

Figure 5-7: Map of Faial

The island of Faial is 8 km west of Pico. Faial has a population of more than 15,000 and a land area of 170 km^2. The island is composed of a single municipality and 13 parishes. Most of the population lives in and around the city of Horta on the eastern side of the island. The economy consists primarily of agriculture and cattle-raising for dairy and meat.

The western group: Flores and Corvo

The two remaining islands in the archipelago lie 250 km west of Faial. Flores has a population of about 4,000 people and covers an area of 140 km^2. The island contains two municipalities, the larger of which is Santa Cruz das Flores. The island economy is mainly agricultural.

Figure 5-8: Map of Flores

Figure 5-9: Map of Corvo

Corvo is the northernmost island in the Azores and also the smallest. It has a population of less than 500 people and an area of 17 km^2. The town of Vila do Corvo is the population center of the island, with agricultural and grazing lands in the surrounding area as well as protected conservation areas.

5.2 Economy of the Azores

The Azores economy is based mainly on small-scale agricultural activities including dairy farming, cheese making, ranching, and fishing. Increasingly, tourism forms a significant share of economic activity in the Azores, drawing on interest in the islands' cultural and natural heritage. Between 2002 and 2006, the number of tourists visiting the Azores each year increased roughly 30%, to almost 400,000.[48]

By the United Nations Convention on the Law of the Sea, the Azores archipelago forms an "exclusive economic zone" (or EEZ), which grants the autonomous region special rights for use of the surrounding ocean resources, including energy production from water and wind. EEZ's typically stretch 200 nautical miles out from the coastline; due to the archipelago's dispersion across a large area, the Azores' EEZ includes an expansive 953,000 km^2.[49]

None of the traditional economic activities on the islands are especially energy intensive, resulting in fairly low total load requirements. Military bases on the islands account for the single-largest electricity demand sector (around 4% in 2004), followed by the milk industry (1.7%) and the "animal food industry" (1.5%).[48] Notably, many dairy farmers on the islands rely on portable diesel generators that they move to remote stations in their fields in order to milk cows. This type of off-grid electricity demand composes a possibly significant share of total energy demand on some islands, with implications for local air quality and fuel costs for farmers.

Tourism represents a growing share of electricity demand, and introduces new dimensions to power supply that may require special attention. Where traditional sources of electricity demand on the islands have relatively flat demand profiles throughout the year, tourism can be subject to major seasonal fluctuations. The influx of thousands of tourists during peak travel periods can result in significant increases to island electricity demand, resulting in the need for additional generation capacity for these limited time periods. Due to the needs of computers and other electronics at tourist-sector businesses, as well as heightened expectations of travelers from abroad, the emerging tourist economy might also bring higher demands for power quality and less tolerance for intermittent blackouts that can result from security of supply violations. On account of these new influences on electricity demand in the Azores, island planners should carefully consider how the power system will need to adapt and perform in future years.

5.3 Political structures

Azores autonomous government and mainland Portugal

The Azores operate as an autonomous region of Portugal, with this status declared for it and Madeira in the Portuguese constitution of 1976. The Azores are governed under a set of regional statutes, with an elected Azorean Parliament taking up key business. Despite this autonomy, the central Portuguese government maintains a role in legislative matters, including required approval of proposed laws by the Portuguese national assembly.

Electric utility governance

A single electric utility, Electricidade dos Açores (EDA), serves all islands of the Azores. EDA is a fully regulated utility and operates as the system operator for all nine islands according to a concession contract with the Azores regional government. EDA owns 85% of generation capacity on the islands—all thermal ICE power plants—and supplies a similar percentage of total electricity.[48] The remainder of generation capacity is owned by independent power producers and includes renewable energy facilities, however those IPPs in practice operate as subsidiaries of EDA. This is in contrast with electricity supply in mainland Portugal, where deregulation of the electricity system was completed in 2006 and is subject to greater competition.

By national law, Azores' electricity customers pay the same retail electricity rates as mainland Portugal. Given the reliance on expensive fuel oil and diesel imports, this means that Azorean electricity is effectively subsidized by the rest of Portugal. EDA planners on the Azores are required to follow least-cost planning procedures when investing in capacity additions or other grid enhancements, however the subsidized rates suggest that total costs will never be fully internalized by ratepayers. Therefore, least-cost planning requirements effectively mean that EDA must seek to minimize this mainland-to-island monetary transfer.[2]

5.4 Azores clean energy goals

In 2008, the president of the Azores Autonomous Region at that time announced a goal for the region to generate 75% of electricity from renewable energy sources by 2018, with an intermediate goal of 50% by 2015.[50] It is unclear what formalized legal standing the goal has or the preferred path to achieve 75%. It is also not entirely clear whether all islands must themselves achieve 75% renewable electricity or if a 75% average across the region would be sufficient. One source actually cites a more modest goal of 40% of primary energy from renewable sources, with 50% of total energy from electricity.[28] The 75% renewables goal is the most widely cited in available media, however, and is the benchmark objective for this research.

[2]For an explanation of how this mainland-to-island tariff structure works in practice, see Perez & Ramos-Real for a discussion of its application in the Canary Islands of Spain.[29]

Achieving the 75% goal may not be possible under the Azores' strategy to-date, which has primarily relied upon build-out of wind generation capacity. This is due to the technical requirements for maintaining security of supply on the grid and a temporal mismatch between availability of wind generation and high demand periods. At wind penetrations of 20% of system demand or greater, significant amounts of wind generation are likely to be spilled[51], and significant voltage control and frequency regulation problems might be encountered[2].

Development of other renewable generation sources can help to balance the problems posed by wind, however other sources such as solar also suffer from intermittency. In at least one planning document, the Azores' government has expressed interest in developing ocean energy sources such as tidal or wave power.[49] At present, however, wind and solar are the most well-developed and economically viable renewable energy technologies, and will very likely factor prominently in clean energy expansion on the Azores. Whatever the ultimate portfolio of renewable resources on the islands, energy storage can play a part in balancing their variable generation, and storage has been found to significantly enhance the ability to achieve 75% clean energy.[21]

5.5 Azores electric power systems

The Azores' electric power system has developed in a relatively short period of time—large parts of the islands remained unconnected to electricity sources as recently as the 1980's—but now operates as critical infrastructure that is vital to daily life. The electric network extends to all towns and residences, and is relied upon for varied uses from lighting and heating to most commercial activity. Growth in electricity demand has been rapid, and EDA has typically relied on adding oil-burning internal combustion engines to stay ahead of rising consumption levels. Further demand growth is expected in the years ahead for continued economic development and for expanded end-uses such as electric vehicles to achieve sustainability objectives, suggesting that capacity expansion will continue for some time to come.

Each of the Azores islands has its own electricity network, without interconnections between islands. The networks are operated at a frequency of 50 Hz—the same as the European continental system. Electricity is transmitted across the island grids primarily on 15 kV power lines (plus a smaller number of 10 and 6 kV lines), then distributed to customers on low-voltage 0.4 kV lines. Terceira and Pico each have a small number of 30 kV lines for higher voltage transmission, while São Miguel has 30 kV as well as 60 kV lines.[48]

The islands all meet N-1 criteria and have capacity reserve margins well above 20%, but at the expense of significant generation capacity that sits idle most of the year. Even so, some Azores islands experience an unacceptably high number of power outages. In 2011, the average cumulative duration of power outages experienced by customers on each island ranged between 50 minutes on Corvo to more than 10 hours on Graciosa. The frequency of power outages ranged from 4 per year on Corvo to almost 25 on Terceira.[52] Those compare to average North American values of around 90 minutes and one interruption per year.[53] Azores' electricity reliability has varied widely from year to year and between islands; in 2010, Corvo had average outage duration of more than three hours, while Pico had the highest outage duration among the islands of more than 20 hours over the year.[54]

The moderately-developed condition of the Azores power sector means that future planning will need to balance desires for new greenfield project development with strategic utilization of the existing infrastructure already built. This section describes the existing electricity systems and end-uses on the islands, based on which subsequent analysis is carried out.

5.5.1 Electricity end uses and demand profiles

Like any power system, the Azores islands' power systems supply electricity according to varying load patterns. Electricity demand follows a fairly regular daily pattern in which demand is low overnight then increases during the day to an afternoon peak. Demand then declines through the later afternoon, followed by a second peak in the evening. In addition to this daily load shape, there are weekly patterns in which demand tends to be lower on weekends than weekdays, and seasonal variations such as increased demand during tourist seasons.

Figure 5-10 shows an annual load profile for São Miguel, divided into 30-minute time steps (17,520 intervals in one year), color-coded for low demand (blue) to high demand (red) times of the day and year, based on megawatts of electricity generated. As this figure illustrates, there are recurring seasonal and daily patterns to when electricity is consumed on the islands—similar to most power systems in the world. In this case, reading horizontally left to right, electricity demand on São Miguel is lowest in the early morning hours between 1 and 7 a.m., then climbs throughout the day until it peaks in the afternoon. One prominent feature of this chart is the right-bending arc seen across the evening hours through the year, representing a change in the hour of sunset and, as a result, the time at which residents turn on lights for evening activities. Notably, this arch indicates a second daily peak load on the island, which in winter months is often higher than the afternoon peak.

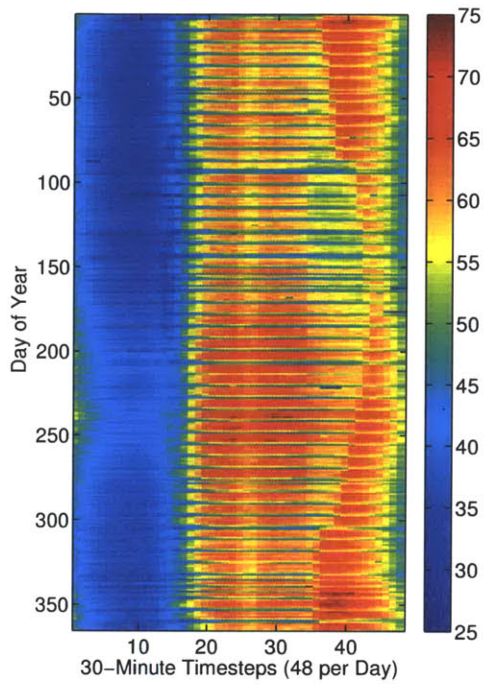
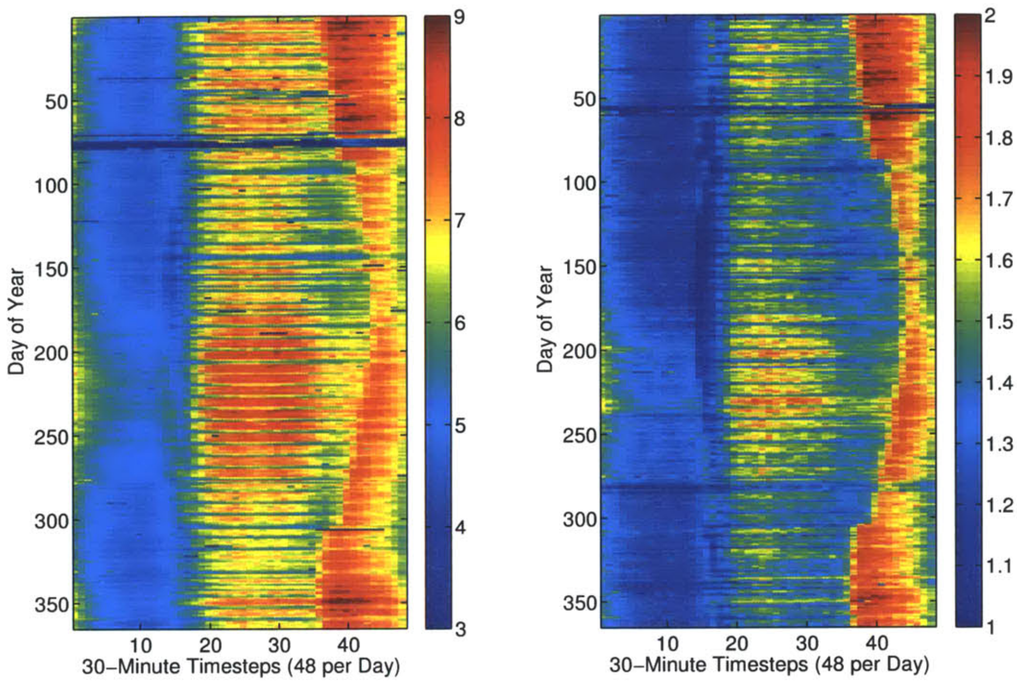


Figure 5-10: Electricity demand profile on São Miguel (2010)

Figure 5-11 shows annual load profiles for Faial and Flores—much smaller islands than São Miguel. These pictures indicate that the seasonal load patterns are similar between different islands, although the size of demand is quite different. (Note the different color scales between the figures; all charts on a MW-scale, however the relative range is quite different.)



(a) Faial

(b) Flores

Figure 5-11: Electricity demand profiles on Faial and Flores (2010)

5.5.2 Island generation portfolios

The first power plant in the Azores was a hydro plant built on São Miguel in 1899, and São Miguel was supplied exclusively by hydropower until 1950.[55] Thermal power plants were built on each of the nine islands during the second half of the century, as well as a small number of geothermal plants and some additional hydro capacity. These days, like many island power systems, the Azores rely predominantly on fuel oil and diesel to generate electricity. In 2010, 72% of electricity in the Azores was supplied by petroleum fuel sources.[6]

The high cost of petroleum imposes a significant economic burden on Azorean energy needs, heightened in recent years as oil prices have risen. Figure 5-12 shows recent costs of fuel oil for Portugal at large and for two Azores islands.[3] While historical data is limited, it is clearly evident that the islands pay a premium above mainland rates, and there is even a premium paid by smaller islands compared to

[3]Portuguese national fuel prices are from the OECD database[56]; Azorean costs were provided by EDA[13] and converted to the common American metric of euro/MMBtu by the author.

the large island of São Miguel. Through 2009, the average cost of high-sulfur fuel oil used for electricity generation in Portugal hovered below 5 €/MMBtu then climbed in the lead-up to the global economic collapse of 2008–2009. More recent prices are not available for that grade oil, however the more expensive low-sulfur fuel oil demonstrates a similar trajectory then climbs steeply between 2009 and 2011. For the years where cost data is available, EDA paid 40–65% more for fuel oil for electricity on São Miguel than the Portuguese average. The small island of Faial, meanwhile, paid a further 25% above average national rates. Although EDA fuel costs are not known after 2008, the chart includes an estimate for how costs might have climbed, assuming that they continued to track low-sulfur fuel oil prices. EDA costs for diesel fuel—as used for electricity on many of the small islands—is not known, however it is likely even more expensive than fuel oil costs.

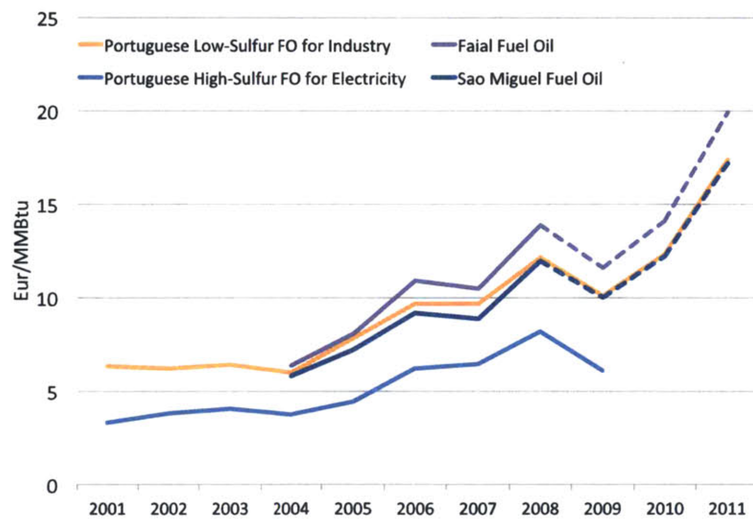


Figure 5-12: Historical fuel costs in the Azores compared to Portuguese average

Table 5.1 provides details for the installed capacity on each of the islands. This data represents the nameplate capacity on the islands to the author's best knowledge of the system at time of writing. Information was gathered primarily from [48] and [57], and supplemented by inspection of half-hourly generation data[6].[4]

Many of the islands have installed capacity well above the annual peak load in order to meet necessary capacity reserve requirements for security of supply. For example, peak load on São Miguel has historically been around 60% of installed capacity

[4]*The 1.8 MW of wind on Faial was dismantled in 2011 and has since been replaced with larger turbines at a different site on the island.[58]

Island	Plant Name	Type	# of Units	Fuel	Capacity (MW)
São Miguel	Caldeirão	ICE	8	Diesel & Fuel oil	98.1
	Pico Vermelho	Geothermal	–	–	13.0
	Ribeira Grande	Geothermal	–	–	14.8
	–	Hydro	7	–	5.1
	Graminhais	Wind	10	–	9.0
Santa Maria	Aeroporto	ICE	6	Diesel	5.7
	–	Wind	3	–	0.9
Terceira	Angra	ICE	4	Diesel	8.8
	Belo Jardim	ICE	10	Diesel & Fuel oil	61.1
	–	Hydro	–	–	1.4
	–	Wind	5	–	4.5
Graciosa	Graciosa	ICE	5	Diesel	3.4
	–	Wind	5	–	0.8
São Jorge	Caminho Novo	ICE	7	Diesel	7.0
	–	Wind	7	–	1.2
Pico	Pico	ICE	6	Diesel & Fuel oil	13.4
	–	Wind	6	–	1.2
Faial	Santa Barbara	ICE	6	Diesel & Fuel oil	14.9
	–	Hydro	–	–	0.3
	–	Wind*	6	–	1.8
Flores	Além Fazenda	ICE	4	Diesel	2.3
	–	Hydro	–	–	1.5
	–	Wind	2	–	0.6
Corvo	Horta Fundo	ICE	4	Diesel	0.4

Table 5.1: Electricity generation plants in the Azores

on the island, while peak load on Terceira has been less than 50%.[48] This represents a costly over-provision of generation capacity, owing to the lack of economies of scale achieved on island power systems. Nonetheless, if electricity demand in the Azores increases as it has for many years, spare capacity will diminish and new generation sources will be needed. Since 1990, total electricity production on the islands has nearly tripled, from 296 GWh to 840 GWh in 2011. In that same period generation from renewable sources has increased more than 10-fold, from 20 GWh to 252 GWh.[55]

5.5.3 Clean energy development

In pursuit of the 75% clean energy goal, the Azores have undertaken a number of clean energy projects and other grid enhancements to manage variable generation and load patterns. EDA sees those projects as "very economic" compared to reliance on oil generation—in 2012, the feed-in tariff rate for renewable electricity was 91.5 euro/MWh, compared to the equivalent of 135 euro/MWh for heavy fuel oil and 219 for diesel.[55] This section provides brief descriptions of some of those projects.

Geothermal power on São Miguel

The first geothermal power plant came online in São Miguel in 1980. That plant was upgraded in 2006 to the present Pico Vermelho plant, and today there are two geothermal plants on the island providing 27 MW of capacity. Generation output from those plants has increased in recent years as a result of plant enhancements undertaken by EDA, and geothermal now provides 50% or more of electricity production on the island in some shoulder-season months.[50, 55]

In pursuit of clean energy objectives, EDA would like to increase geothermal power output on São Miguel. The utility has proposed either increasing capacity at the Pico Vermelho plant by 10 MW or building a new 8–12 MW geothermal facility on the island.[28]

Wind projects

The Azores have pursued wind generation as their primary strategy for renewable energy development, and currently have around 20 MW of installed wind capacity with projects on all islands except Corvo. To date, wind farms on the islands have been relatively small—many include only a handful of turbines of less than 500kW each.

Early wind projects were installed on the smaller islands, including Flores and Faial. The Faial project, built in 2002, never performed to full expectations due in part to noise complaints from local residents that led to the turbines being shut off for 5.5 hours every night. The Faial turbines were subsequently dismantled and relocated to other islands, while a new larger wind farm was built elsewhere on the island away from houses.[58] In 2011, the Graminhais wind farm entered service on São Miguel, becoming the largest wind development in the Azores. The ten 900 kW turbines at the site are predicted to generate around 22 GWh of electricity annually, or 10% of the island's demand.[59]

Wind development continues in the Azores, with planned expansion of existing wind farms and new projects under development on many islands including Terceira, Graciosa and Santa Maria.[59] The Graminhais wind farm represents a significant step forward in the development of large-scale wind generation in the Azores; if wind is to play a significant role in achieving the 75% clean energy target for the islands, more large projects of this type will be needed.

Flywheels on Flores and Graciosa

A flywheel was installed on Flores in 2004 in order to maintain grid stability and power quality in the face of increasing renewable generation. At that time, installed capacity on Flores was 2.3 MW of diesel units, 1.35 MW of hydro, and 0.6 MW of wind. The increasing penetration of renewable sources introduced operational challenges due to the intermittency of wind combined with variable load patterns on this small island. The fast-response storage device has a capacity of 500 kW and can charge or discharge for up to 30 seconds at full power.[5] The flywheel is capable of providing the frequency response service that would otherwise be served by the diesel units; as a result, Flores has achieved operating periods of 100% renewable generation during low demand days from the combination of hydro and wind generation.[55] There is also a flywheel installed on Graciosa, and interest in adding more flywheels on other Azores islands.

NaS battery with renewables project on Graciosa

In addition to the flywheel, Graciosa is the focus of another energy storage project. EDA has partnered with the German company Younicos to build an integrated renewable generation and battery storage system on the island.[55, 60] The final design remains in development, but the system is planned to include six 900 kW wind turbines (5.4 MW total), a 0.5 MW solar PV plant, and 2.5 MW of sodium-sulfur battery storage. NaS batteries were selected for their proven performance and long-lifetime—the batteries are expected to last 15 years or 4,500 full discharge cycles. The project will provide 70% of the island's total electricity needs, reserving the existing diesel units for backup power and peak demand periods. The project was scheduled to be completed in 2012, however it is not known to be operating as of this writing. Since 2010, Younicos has tested designs and technologies at a one-third scale demonstration project at their headquarters in Berlin. Younicos will own and maintain the installation while EDA will continue to own and operate the island grid. Younicos will be paid according to an avoided fuel cost remuneration structure.

5.6 Prior Azores energy planning studies

A handful of studies have analyzed the Azores electricity system to assess the technical and economic feasibility of achieving the region's clean energy goals. For example,

[5] The Flores flywheel is actually a low-speed device (1800–3300 rpm) compared to other flywheel designs and is coordinated with the island grid by use of on-site power electronic converters.[55]

Monteiro da Silva provides helpful historical context for renewable energy on the islands, with case studies focused on Flores and Corvo.[61]

Moreira da Silva uses a multicriteria decision method to compare energy storage and other planning options for sustainable development on São Miguel, with emphasis on criteria for carbon emissions, total costs and reliability.[28, 62] Parness also investigates sustainability options on São Miguel, with attention to optimal charging strategies for electric vehicles in order reduce electricity and transportation costs and reduce CO_2 emissions.[14]

DeAmicis characterized wind and hydro generation patterns in the Azores, finding that high capacity of variable renewable generation would impose significant reliability challenges on the islands, for which fossil fuel generation is needed to provide reserves.[21] In a case study of Flores, DeAmicis investigates the effects of coupling storage with high penetration of renewables and finds that storage would increase the total generation from those resources because storage can provide spinning reserve in place of keeping fuel units online at minimum generation levels.

5.7 Azores islands for analysis

In light of diverse characteristics for population size and density, economic activity and existing power system infrastructure, among others, every island power system is unique and requires careful attention for network planning and optimal investments. That situation means that cookie-cutter designs for technology investments and network upgrades cannot be applied across all islands. To do so would result in imperfect matching of technology investment to island conditions, at best, and possibly failed projects and significant waste.

The nine islands of the Azores are a microcosm of this reality for islands worldwide: each island in the archipelago has unique circumstances for the local economy, island geography, existing grid infrastructure, and future prospects. Moreover, the energy demands and installed capacity on the islands span orders of magnitude difference, from Corvo with less than 0.5 MW of capacity to São Miguel with almost 150 MW. This presents a planning challenge for the EDA utility and Azores government, made more acute by the limited resources and expertise available on the islands.

In order to gain insight on how differences in islands affect investment choices, this research investigates three out of the nine islands in the Azores: São Miguel, Faial, and Flores. Those islands were selected for the notable differences they exhibit between one another. Most obvious, the islands represent three different sizes with respect to land area, population, and energy demand. Table 5.2 provides some detail on how the islands compare across different measures of size.

	Land Area	Population (approx.)	Peak Load (2010)	Generation Capacity
São Miguel	750 km^2	140,000	74.2 MW	140 MW
Faial	170 km^2	15,000	9.4 MW	17 MW
Flores	140 km^2	4,000	2.1 MW	4.4 MW

Table 5.2: Size comparison of São Miguel, Faial and Flores

In addition, the selected islands provide three very different existing generation portfolios. Where São Miguel benefits from a large capacity of geothermal power that provides nearly half of island electricity, Faial is almost completely dependent on fuel-burning ICE units. Flores, meanwhile, has relatively large amounts of installed renewable capacity in the form of hydro and wind, but this means that Flores is already subject to significant variable generation from renewables.

Figure 5-13 compares the hourly load profiles of the three islands over a single week.[6] In addition to the different magnitudes of system size, this figure shows some differences in the hour-to-hour shape of demand between islands. While every island demonstrates some amount of variability, it appears that demand on the big island of São Miguel is more regular and predictable, whereas greater variability is observed as the islands become smaller. This is not surprising—small power systems are expected to be less predictable because the autonomous decisions of single-end users will tend to have a greater relative impact on total demand on small systems. This means that load forecasting will tend to be more difficult on small islands such as Flores, and suggests that there might be greater need for fast-responding flexible power supply sources.

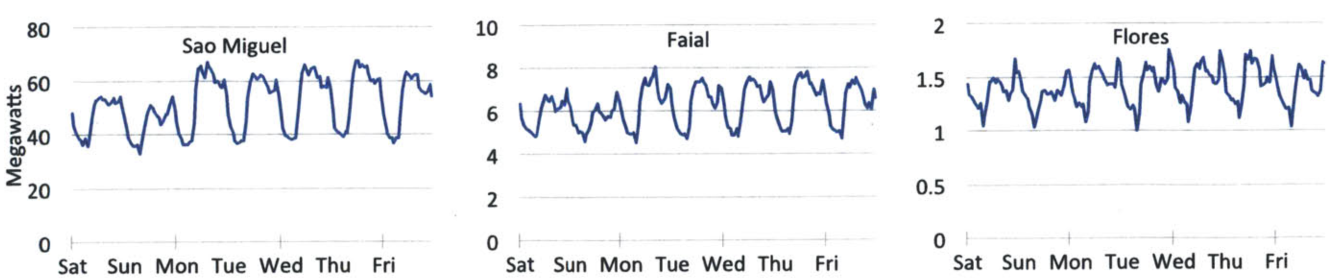
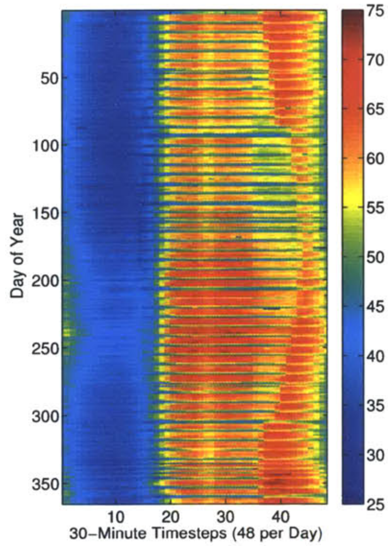


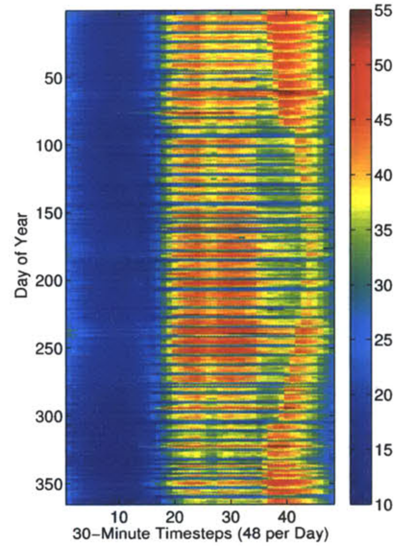
Figure 5-13: Weekly demand profiles on São Miguel, Faial and Flores

[6]Derived from generation data for the week of June 26, 2010.

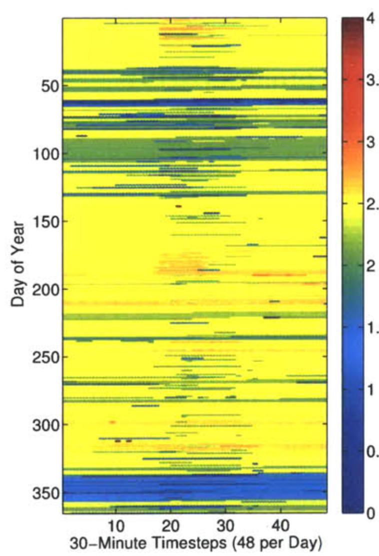
Figure 5-14 shows the total generation on São Miguel in 2010, distinguished by generation type. As can be seen from the very similar color patterns for oil generation and the total generation profile (reproduced from Figure 5-10), the oil units are relied upon for nearly all load-following generation needs. This reliance on oil and diesel generation for the majority of electricity generation, as well as ramping and load following, is similar on other islands in the Azores. The two bottom panels of Figure 5-14 show renewable generation over the course of the year. Where hydro power operates over a range of 0–4 MW during the year, with typical output of around 2.5 MW, the two geothermal plants generate as flat baseload output through all hours of the year. The only significant variation is attributable to two capacity uprates made to the plants during 2010: the first in the early summer and the second near the end of the year. Wind generation was not yet installed on São Miguel in 2010, thus no hourly wind profile is available for this discussion.



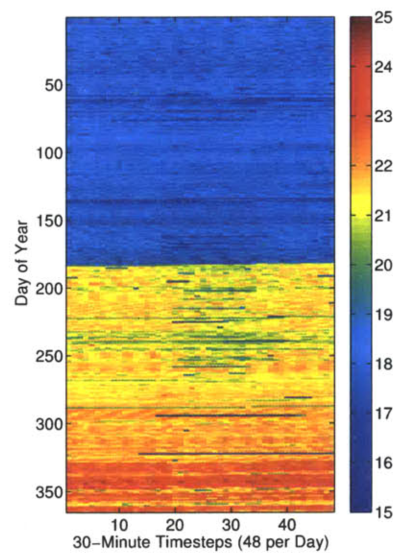
(a) Total Gen



(b) Oil



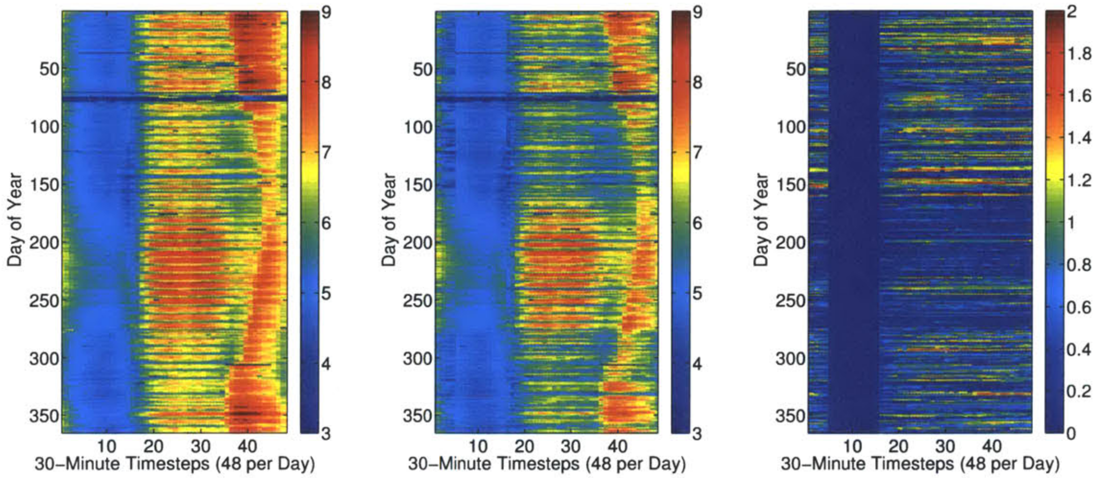
(c) Hydro



(d) Geothermal

Figure 5-14: São Miguel generation profiles (2010)

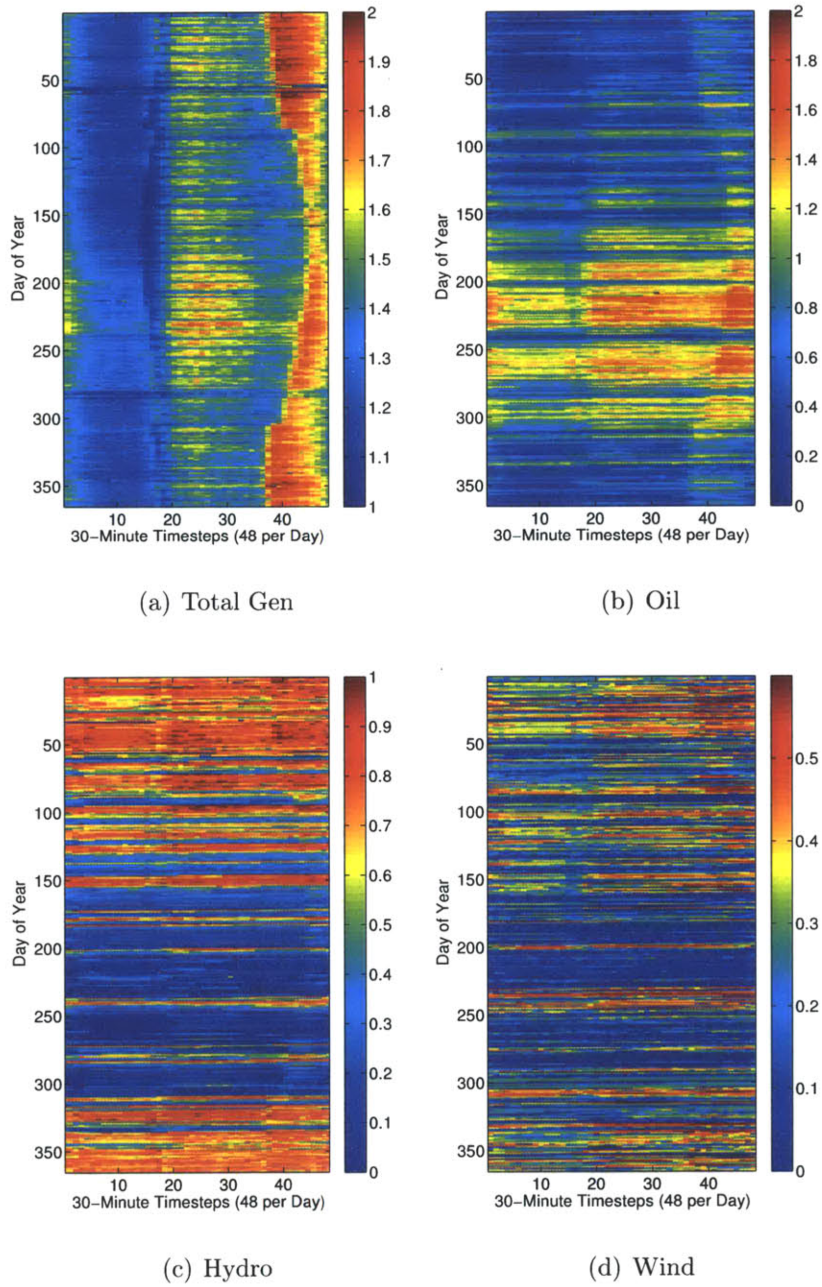
Figure 5-15 shows the total generation on Faial. Oil generation accounts for more than 90% of electricity generation on Faial, and is relied on for both load following and balancing generation from the island's 1.8 MW wind farm. In this figure, the overnight hours stand out on the wind chart, where the six wind turbines are required to turn off for 5.5 hours to limit noise disturbance of local residents. This nightly event is also evident on the oil generation chart, where a faint increase in generation is evident in the same hours.



(a) Total Gen (b) Oil (c) Wind

Figure 5-15: Faial generation profiles (2010)

Hourly generation patterns are shown for Flores in Figure 5-16. On Flores, where half of all electricity was supplied by renewable resources in 2010, the effects of variable generation is readily apparent. While total generation has a clear seasonal and daily pattern, both hydro and wind are highly variable. In particular, the hydro plants demonstrate a significant seasonal effect of relatively high generation in the winter and spring, followed by almost zero output in the summer and fall months. Wind, on the other hand, demonstrates intermittency between hours as well as weeks, and happens to be very low for some of the same weeks as hydro. As a result, oil generation is relied upon to fill the supply gap throughout the year—whatever it might be at any time—and is seen to produce at its highest level during the summer months.



(a) Total Gen

(b) Oil

(c) Hydro

(d) Wind

Figure 5-16: Flores generation profiles (2010)

Chapter 6

Research methods

This chapter provides a brief overview of modeling techniques commonly used in electric power system planning, with special attention to modeling of island power systems and energy storage. Following the modeling overview and discussion of relevant research, a least-cost unit commitment model is presented for application to the Azores. The chapter concludes with a discussion of the key assumptions used in this research.

6.1 Prior work

6.1.1 Modeling of power systems

Researchers and planners of electric power systems rely heavily on engineering and economic models in order to test various designs for the network. For many years, linear programming and optimization models have been used to determine least-cost designs and operation of the system while satisfying technical and economic constraints for generation and transmission system assets, as well as regulatory requirements such as reliability and environmental emissions.[63] Over the past 20 years, research interest in power system modeling has accelerated as electricity markets in many parts of the world underwent deregulation and are now subject to greater economic competition, and as computing power increases and new modeling techniques are developed.

Generation scheduling (or unit commitment) and economic dispatch of power plants involve some of the most fundamental modeling questions for power systems and underly this research. Yamin provides a review of methods for generation scheduling, covering the development of techniques since the 1950's and focussed on deterministic and heuristic approaches.[64] Linear programming (LP) and mixed-integer linear programming (MILP) techniques are commonly used for unit commitment (UC) modeling, resulting in a schedule for each generator that satisfies total demand in each period while complying with various constraints such as minimum and maximum output by generation units, limitations on ramp speed for each unit, and minimum up and down times. García González provides a detailed description of unit commitment modeling techniques and mathematical formulations.[65]

In practice, unit commitment models can be developed in a variety of ways, and the precise formulation of any problem will depend on the relevant information that is sought. Typically, unit commitment problems are modeled according to hourly demand forecasts and generation schedules over durations of a single day or week, but other time-steps and durations are possible. In one-week UC models, a Saturday-to-Friday week is commonly modeled, reflecting the demand cycle in which electricity demand is higher on weekdays than weekends, and therefore thermal power plants are often started on Monday then shut off on Friday. Basic UC models also apply a "single-node" approach that does not include any representation of the transmission network, therefore ignoring possible transmission line constraints. Where transmission constraints are present, generator operating modes such as "must-run" can be forced into the model in order to ensure transmission feasibility. Typically, unit commitment problems will not directly account for uncertainty, as the model will optimize generation schedules deterministically over a forward-looking period with perfect foresight for relevant parameters such as hourly demand levels and fuel costs. In order to account for future uncertainty, scenario-based modeling can be applied to unit commitment problems. Scenarios are commonly developed for factors such as fuel costs, environmental regulations, power plant construction and retirements, and long-term demand growth.

Operating reserves are modeled in order to ensure that adequate generation capacity is available in each hour to cover possible deviations in load and wind forecasts or generator outages. For modeling purposes, reserve requirements are commonly formulated either as a fixed capacity amount or a percentage of expected load. Reserve requirements introduce a constraint in unit commitment problems that, depending on how requirements are set, can significantly alter generation schedules and resulting total costs. Unit commitment models typically do not account for other types of reserves, such as reactive power reserve or long-term capacity planning reserve.

Integration of variable-output renewable generation sources such as wind introduces new challenges to power system operations and to modeling, alike. At low penetrations of wind—of less than 10–15% of total system generation—variability will tend to be small relative to the larger system. In these cases wind and other renewables are often modeled according to a "net load" approach, in which dispatchable power plants are scheduled against forecasted demand in each hour *net* of forecasted renewable generation. In some systems, additional operating reserves are now required specifically to account for uncertainty in wind forecasts, and these reserve levels will be relatively larger than load reserves owing to the greater uncertainty on wind. As wind penetration increases, introducing larger swings in wind output relative to the total system and greater risks from uncertain wind patterns, the net load approach becomes inadequate—in modeling as well as actual operations.[3]

Significant research attention is currently directed toward development of advanced modeling techniques to more accurately reflect operational uncertainties in power systems—namely from renewables—and to support new operating procedures that can incorporate large amounts of renewable generation while meeting or improving upon reliability criteria. The emphasis of that body of work is to better account for the stochastic nature of power system operations and renewable generation, rather than strictly deterministic approaches. For example, Bouffard et al incorporate stochastic wind availability into a short-term electricity market clearing problem that is designed to enable greater penetration of wind without loss of security.[66] Wu et al model uncertainty by use of Lagrangian relaxation in a "master and subproblem" formulation in order to minimize operating costs over a probabilistically weighted scenario tree using Monte Carlo simulation techniques.[67] Meibom et al enhance the standard day-ahead unit commitment approach, as used in many power system operations, with a rolling decision for unit commitment as wind forecasts are updated closer to real-time. The model is applied to Ireland (an island power system, if a very large one) and suggests that wind is capable of serving more than 30% of total demand without imposing reliability problems or requiring significant wind curtailment.[68] Other research has investigated advanced modeling techniques for operating wind-heavy power systems, such as "particle swarm optimization" algorithms[69], hybrid deterministic unit commitment and stochastic unit commitment formulations[70], and stochastic dynamic programming methods[71].

Higher penetrations of intermittent renewables is leading to new demands on other power plants on the system to balance wind variability. Fast-ramping combined-cycle gas turbines (CCGTs) or other gas- and oil-burning plants are now relied upon for on/off cycling and renewables "shaping" to a greater extent than has historically been the case. In response, new operating procedures and contract terms are being explored to properly account for these services, as well as long-term planning procedures. For example, Batlle et al describe inadequacies in operation & maintenance service agreements for CCGTs, and investigate new modeling techniques to limit stops and starts of those units across a fleet of plants.[72, 73] Palmintier and Webster present a new method for combining unit commitment constraints with long-term capacity planning decisions for systems with high penetration renewables; their results suggest that ignoring these constraints can lead to sub-optimal capacity mixes in the future.[74]

6.1.2 Modeling of island power systems

In the past decade, a variety of reports and research articles have focused specifically on development of renewable energy on island power systems. Island systems are sometimes investigated under the broader characterization of "autonomous energy systems", which includes buildings or district energy systems and isolated power grids in remote locations, such as rural communities in developing countries.[75] Those systems share similarities with islands in terms of network size and applicable generation technologies, and some of the same modeling and analytic techniques can be applied to a variety of autonomous energy systems. Every system remains unique, however, and individual attention to the particular generation resources and energy demand patterns of each system is needed for planning and investment purposes.

A number of studies focus on the Aegean islands in the Mediterranean.[1, 76, 77] For example, Kaldellis et al (2001) investigate the potential for a coupled wind-hydro station on the island of Ikaria (peak load of 4.2 MW in 1998), including the optimal capacity of each generation type, and find that renewable resources can reliably supply over 90% of electricity demand while reducing total costs and emissions.[76] Other studies take a variety of other islands for their analysis. Marrero and Ramos-Real, for example, apply a mean-variance portfolio analysis to the Canary Islands and conclude that natural gas power plants would complement the variability of renewable resources while reducing both total costs and risks, as well as CO_2 emissions.[16] De Vos et al present a unit commitment model of Cyprus to explore the adequacy of current reserve requirements to support increasing penetrations of wind power.[4]

6.1.3 Modeling of energy storage

The emergence of energy storage as an attractive and viable technology solution has spurred great research interest in the best applications for storage. Some articles have used commercially available software to assess small-scale battery storage for renewable integration into building-level systems[78]—system sizes which might also have applicability to small islands. Oudalov et al investigate the relative monetary value available from bulk energy storage for different grid services and find that the highest value is available from frequency control services.[79]

Denholm and Kulcinski analyze the life-cycle greenhouse gas emissions from energy storage systems coupled with electricity generation. They find that greenhouse gasses from renewable generation coupled with storage are less than fossil fuel generation alone, and that pumped-hydro storage is less than CAES or battery systems. When fossil fuel generation is coupled with storage, however, CAES systems have the lowest greenhouse gas intensity.[80]

Other research has incorporated energy storage into unit commitment models to investigate the impact of storage on generation scheduling and dispatch. Hargreaves and Hobbs include storage in a stochastic dynamic programming UC model of uncertain wind generation, with parameters for storage power (MW) and both charging and discharging losses but not for capacity (MWh).[71] Other research has modeled large power systems with pumped-hydro storage in competitive spot markets.[81]

Due to the heightened challenges from intermittency on islands and the favorable economics for integrating high-cost technologies, many island studies find a strong case for energy storage development coupled with renewables. Kaldellis et al (2009) compare different renewable energy and storage technology combinations for a set of differently sized islands in the Aegean archipelago.[1] Zafirakis and Kaldellis investigate compressed air energy storage (CAES) for balancing wind intermittency on Crete.[77] Duić and Carvalho present a model for the integration of hydrogen fuel cells and batteries with renewables on the island of Porto Santo, in Madeiro, Portugal.[2]

As energy storage technologies improve—and the set of technologies expands from familiar systems like pumped-hydro to flywheels and a diverse set of battery designs—new modeling techniques are needed to reflect their specific designs and performance. Simplistic representations for rated power and energy losses should be replaced with more detailed approximations for available power and efficiencies at different charge states, performance degradation over time, and specific energy services that can be served—including at short time-scales of minutes and seconds. Those capabilities will improve as specific technologies gain prominence and as knowledge is gained from field installations. At this time, however, "The ability to simulate the cost impacts of variable generation and benefits of storage is still limited by the methods and data sets available."[82]

6.2 Description of model for island power systems

In this research, a unit commitment model is presented that focuses on integration of variable renewable resources and energy storage, for application to small- and medium-sized islands. The model optimizes generation commitment and dispatch for a one-week time horizon based on hourly time steps. The following sections provide the mathematical formulation of the model and its main outputs. The model is developed specifically for the Azores, however it can easily be adapted to similar island power systems that also rely heavily on fuel-burning internal combustion engine (ICE) generators. While the general structure could be applied to other variable generation technologies such as solar, this formulation describes the model with respect to wind generation.

The model is formulated as a mixed-integer linear program (MILP), written in the General Algebraic Modeling System (GAMS) language and solved by the CPLEX optimizer. The optimality gap is set to 0.01 (1%). Given the small size of the island power systems under review, most model runs solve extremely fast at this optimality gap (less than five seconds), however some runs—especially those with high penetrations of wind and high wind availability during the week—are slow to solve (requiring 15 minutes or longer). The optimality gap of 0.01 strikes a balance between reaching close-to-optimal results and having a model that solves quickly—especially important in model runs where more than 50 storage designs are tested at once. An example of the GAMS code is provided in Appendix A.

6.2.1 Mathematical formulation

Equation 6.1 describes the cost minimizing objective function of the model.

$$minimize \sum_{t} \sum_{g} FuelCosts + VOMCosts + StartupCosts \tag{6.1}$$

The objective value resulting from this function is the weekly costs of operations from electricity generation, ignoring investment costs or longer-term fixed costs from operating the system. Costs are calculated according to a standard operating cost formulation, in which generation incurs variable costs from fuel consumption (dependent on the cost of fuel and efficiency of fuel-to-electricity conversion by each generating unit), variable operation and maintenance (VOM) costs that scale with the level of generation by each unit, and start-up costs for each time a unit is brought online. In addition, there may be specific costs incurred from unit shutdowns, and some unit commitment formulations will include a term for those costs; in this formulation, shutdown costs are assumed to be captured in the startup term because for every startup there is by necessity also a shutdown.

The cost components of the objective function (6.1) are calculated as follows.[1]

$$FuelCosts = x_{g,t}\frac{F_g H_g}{1000} \quad \forall g, t \tag{6.2}$$

$$VOMCosts = x_{g,t}V_g \quad \forall g, t \tag{6.3}$$

$$StartupCosts = p_{g,t}P_g \quad \forall g, t \tag{6.4}$$

Efficiency is modeled here by the American convention of "heat rates", or Btu of fuel burned per kWh of electricity produced (Btu/kWh). In this analysis, all costs are linear approximations, including constant heat rates over the full range of output of fuel units; future work might consider a piecewise linear approximation of generator efficiency to more closely match actual heat rates for partially- and fully-loaded generation.

In this research, renewable resources (including wind, hydro and geothermal generation) are assumed to have zero operating costs, making these units preferred for dispatch in the model. This assumption is appropriate to match actual operations, in which renewable resources are often given priority dispatch to achieve public policy objectives. Variable costs for these resources are assessed during post-processing of model results, based on known feed-in tariff and power purchase agreement (PPA) rates.

The objective function is subject to a number of constraints, which are described in the following subsections.

Demand balance

Generation is required to meet forecasted demand in every hour—without the option for load curtailments or non-served energy.

$$\sum_g (x_{g,t}) + \hat{s}_t^p = D_t + \check{s}_t^p \quad \forall t \tag{6.5}$$

The left-hand side of Equation 6.5 (total generation in each hour) includes a non-negative variable for the amount of energy discharged from storage, while the right-

[1] In practice, costs are formulated in the model having two components: variable generation costs which include both fuel and VOM costs scaled by the level of generation, and startup costs for each start of the unit. This formulation in shown in the GAMS code provided in Appendix A.

hand side (energy demand in each hour) includes the forecasted demand plus a non-negative variable for energy charged into the storage unit.

Generation limits and commitment state

Equations 6.6 and 6.7 restrict the output of each generator to below its maximum capacity and above its minimum generation level in each hour.

$$x_{g,t} \leq u_{g,t}\overline{X}_g \quad \forall g,t \tag{6.6}$$

$$x_{g,t} \geq u_{g,t}\underline{X}_g \quad \forall g,t \tag{6.7}$$

Equation 6.8 requires the commitment state for each generator in each hour to depend on the status of the generator in the previous hour as well as the decision to turn the generator on or off.

$$u_{g,t} = u_{g,t-1} + p_{g,t} - q_{g,t} \quad \forall g,t \tag{6.8}$$

Equation 6.9 introduces a variable $w_{g,t}$ for purposes of calculating ramping constraints, and defines the total output of each generator to be the sum of that generator's minimum output level plus the amount of generation above minimum output. Equations 6.10 and 6.11 (ramp up and down, respectively) restrict the change in output of each generator between successive hours to be less than the maximum ramp rate of the generator.

$$x_{g,t} = u_{g,t}\underline{X}_g + w_{g,t} \quad \forall g,t \tag{6.9}$$

$$w_{g,t} - w_{g,t-1} \leq J_g \quad \forall g \tag{6.10}$$

$$w_{g,t-1} - w_{g,t} \leq J_g \quad \forall g \tag{6.11}$$

Equations 6.12 and 6.13 define the minimum up and down time of generators, and are formulated according to the approach described in [83].

$$u_{g,t} \geq \sum_{t^*}^{t} p_{g,t^*} \quad (where \quad t^* \leq t, \quad and \quad t^* > t - \overline{K}_g) \quad \forall g,t \tag{6.12}$$

$$1 - u_{g,t} \geq \sum_{t^*}^{t} q_{g,t^*} \quad (where \quad t^* \leq t, \quad and \quad t^* > t - \underline{K}_g) \quad \forall g,t \tag{6.13}$$

Wind generation with curtailment

Wind generation is available up to the capacity that is forecasted in each hour, allowing for economic curtailments.

$$x_{gw,t} \leq \overline{X}_{gw,t} \quad \forall t \tag{6.14}$$

This is formulated as a "committable" wind resource up to the maximum wind availability in each hour, as determined by the forecasted wind capacity factor in that hour multiplied by the installed wind capacity. Because wind is available at zero-cost, curtailments will be economic in cases when high costs can be avoided from expensive start-up or shut-down of non-wind units or where the system is unable to provide sufficient reserves for wind. In actual operations, wind curtailment by *a priori* "commitment" could result from a scheduling decision to take a portion of wind turbines offline in future hours, leaving uncertainty for how much energy the remaining units will ultimately produce. In scenarios for high installed wind, this form of curtailment might be necessary to maintain system reliability, especially in windy hours.

Energy storage

Energy storage is modeled as a single storage installation that is sized by capacity (MWh) and charge/discharge rate (MW).

$$s^e_t = s^e_{t-1} + L^S \check{s}^p_{t-1} - \hat{s}^p_{t-1} \quad \forall t \tag{6.15}$$

$$c^s_t + d^s_t \leq 1 \quad \forall t \tag{6.16}$$

$$\check{s}^p_t \leq c^s_t \check{S}^p_t \quad \forall t \tag{6.17}$$

$$\hat{s}^p_t \leq d^s_t \hat{S}^p_t \quad \forall t \tag{6.18}$$

$$s^e_t \leq \overline{S}^e \quad \forall t \tag{6.19}$$

$$s^e_t \geq \underline{S}^e \quad \forall t \tag{6.20}$$

Equation 6.15 maintains "storage balance" for the storage unit, whereby the level of stored energy at the start of each hour must be equal to the amount of energy in the previous hour plus energy charged minus energy discharged. Energy losses through the full storage cycle are approximated by an efficiency penalty (L^S) imposed on the charging term. Equation 6.16 requires that the storage unit can only charge or discharge (or neither) in each hour, but it cannot do both. Equations 6.17 and 6.18

limit the amount of charging and discharging to the power limit of the storage unit. Equations 6.19 and 6.20 limit the total amount of energy stored to be less than the maximum capacity of storage and greater than the minimum (the minimum being imposed in order to prevent "deep discharge" of the storage device, which can damage future performance).

Reserve requirements

Reserve requirements are formulated in order to ensure sufficient capacity is committed in each hour to provide spinning reserves for uncertainties in demand and wind forecasts. Equations 6.21 and 6.22 define the requirements for reserves up and reserves down, respectively, while Equation 6.23 requires additional non-spinning reserve.

$$\sum_{gnw}(u_{gnw,t}\overline{X}_{gnw}) - \sum_{gnw}(x_{gnw,t}) + [d_t^s \hat{S}^p - \hat{s}_t^p + \check{s}_t^p] \geq R^D D_t + R^W x_{gw,t} \quad \forall t \tag{6.21}$$

$$\sum_{gnw}(x_{gnw,t}) - \sum_{gnw}(u_{gnw,t}\underline{X}_{gnw}) + [c_t^s \check{S}^p - \check{s}_t^p + \hat{s}_t^p] \geq R^D D_t + R^W x_{gw,t} \quad \forall t \tag{6.22}$$

$$\sum_{gi}(u_{gi,t}) \leq [Count \quad of \quad Fuel \quad Units] - 1 \quad \forall t \tag{6.23}$$

In this formulation, fixed percentages of both the demand forecast and "committed" wind is required to be online and available as spinning reserve in every demand period. The reserve requirement on *committed* wind allows a lower reserve requirement than would be required for the full wind forecast, as well as introduces an additional rationale for wind curtailment: that wind curtailment might be justified in order to reduce the need for committing expensive generation units running at or near minimum-output levels just for the purpose of maintaining higher reserves against expected wind. The required percentages of reserves up and reserves down for each reserve type (demand and wind) is assumed to be the same (i.e. reserve up requirement = reserve down requirement).

Importantly, storage is assumed to be available to provide both up and down reserves. In this formulation, storage is available to discharge energy for reserves up (Equation 6.21) at the maximum discharge rate of the storage unit minus the scheduled discharge amount for that hour (i.e. reserves are available from the remaining storage "headroom" in each hour). In addition, in hours when the unit is scheduled to charge, storage can provide reserves up equal to the scheduled charge rate (i.e. storage charging can be interrupted in order to reduce total load). A similar formulation is made for reserves down (Equation 6.22).

In addition, a tertiary reserve requirement is imposed (Equation 6.23) that requires at least one ICE fuel unit to be uncommitted in every operating period, in order to be available as a fast-start non-spinning reserve. In cases where the available ICE units are not of a uniform capacity (e.g. São Miguel), the unit reserved for non-spinning reserve must be from the set of larger fuel units.

End of week commitment states

Circular lag operators are employed in the model formulation in order to force unit commitment states in the last hour of the week to be compatible with commitment states in the first hour (i.e. the weekly model treats hour 168 as immediately preceding hour 1). This requirement is imposed in order to force generation units to finish the week in an operating state that is compatible with the start of the following week. This requirement is especially important for modeling energy storage, where storage would otherwise be depleted to minimum capacity by the end of the week in the least-cost solution.

List of symbols

<u>Sets and indices</u>

g ... Generation units

gw ... Subset of g for wind generation

gnw ... Subset of g for non-wind generation

gi ... Subset of g for fuel-burning ICE units only

t ... Hours of the week (1 to 168)

<u>Parameters</u>

D_t ... Forecasted demand in each hour t (MW)

Generator parameters

$\overline{X}_g$ ... Maximum generation level of generator g (MW)

$\underline{X}_g$ ... Minimum generation level of generator g (MW)

$\overline{X}_{gw,t}$ ... Maximum wind generation in hour t, based on forecasted wind (MW)

F_g ... Fuel cost of generator g (Euro/MMBtu)

H_g ... Heat rate of generator g (Btu/kWh)

V_g ... Variable operations & maintenance cost of generator g (Euro/MWh)

J_g ... Maximum ramp rate of generator g (MW/hour)

$\overline{K}_g$ ... Minimum up time of generator g (hours)

$\underline{K}_g$ ... Minimum down time of generator g (hours)

U_g ... Startup cost of generator g

Storage parameters

$\hat{S}^p$ ... Maximum discharge power of storage (MW)

$\check{S}^p$ ... Maximum charge power of storage (MW)

$\overline{S}^e$ ... Maximum energy capacity of storage (MWh)

$\underline{S}^e$ ... Minimum energy capacity of storage (MWh)

L^S ... Roundtrip efficiency of storage (i.e. 1 minus % losses)

Reserve requirements

R^D ... Reserve requirement on forecasted demand

R^W ... Reserve requirement on "committed" wind

Variables

All variables are non-negative

$x_{g,t}$ ... Output of generator g in hour t (MW)

$w_{g,t}$ ... Output of generator g in hour t, net of minimum generation level (MW)

$\hat{s}_t^p$ ... Amount of power discharged by storage unit s in each hour t (MW)

$\check{s}_t^p$ ... Amount of power charged by storage unit s in each hour t (MW)

Binary variables

$u_{g,t}$ ... Unit commitment state for unit g in hour t (1 = on)

$p_{g,t}$ ... 1 to turn on unit g in hour t, 0 otherwise

$q_{g,t}$ ... 1 to turn off unit g in hour t, 0 otherwise

c_t^s ... 1 if storage is charging in hour t, 0 otherwise

d_t^s ... 1 if storage is discharging in hour t, 0 otherwise

Scenario looping

The model can be formulated to solve a selection of scenarios in series in a single run. In the formulation used in this research, the model loops over a set of scenarios for storage capacity and power, holding other input parameters constant. The GAMS structure of that formulation is shown in Appendix A.

6.2.2 Outputs of model

In addition to the weekly operating cost of the system (i.e. the objective value of the model), a variety of performance metrics can be calculated from the model results. These include the number of starts and stops by each unit, hourly generation of units, storage charge and discharge amounts in each hour, and amount of wind energy curtailed from what is available in each hour. In addition, other metrics and results can be calculated from post-processing of model outputs, such as amount of generation from renewable resources and estimated carbon emissions. In this work, estimates for total annual costs and generation are also obtained from a probabilistic assessment of high, medium and low wind weeks.

6.3 Data sources and assumptions

Input data for this research is collected from a combination of Azores historical data provided by EDA, values from other academic literature, and publicly available information. These modeling inputs are explained in the sections that follow.

6.3.1 Input assumptions

Electricity demand

Weekly load shapes are derived from 2010 historical generation data provided by EDA. The 2010 data demonstrates limited variation in total load between different weeks of the year, and the hour-to-hour load shape is similar between different seasons. The main differences across the year are the time of day when the evening peak load occurs and some variation in total load. On each of the three islands investigated, the total energy in the lowest demand week of the year is 80% or greater the total energy in the highest demand week—a relatively flat annual demand profile compared to larger power systems. Figure 6-1 shows a sample of three load shapes for São Miguel in 2010; the weeks are selected to represent seasons with relatively low, medium, and high total generation, and illustrate this limited variation across the year. Similar to São Miguel, the week of June 26 was a medium-demand week on Faial and Flores in 2010. In light of the similar load shape through the year, and to reduce the number of scenarios needed on top of those required for three islands and dozens of wind assumptions and storage sizes, the load shapes for the week of June 26 on each island is used in all model runs.

In the near term, EDA expects load to grow at 3% per year, then slower growth over the long-term in later years.[28] There is reason to believe that this load forecast is unrealistically high, however. Among other reasons, mainland Portugal electricity demand has remained flat in recent years due to a combination of energy efficiency measures and economic recession. While the Azores might have higher growth potential than the mainland, the islands also experienced some decline in electricity demand due to the recession.

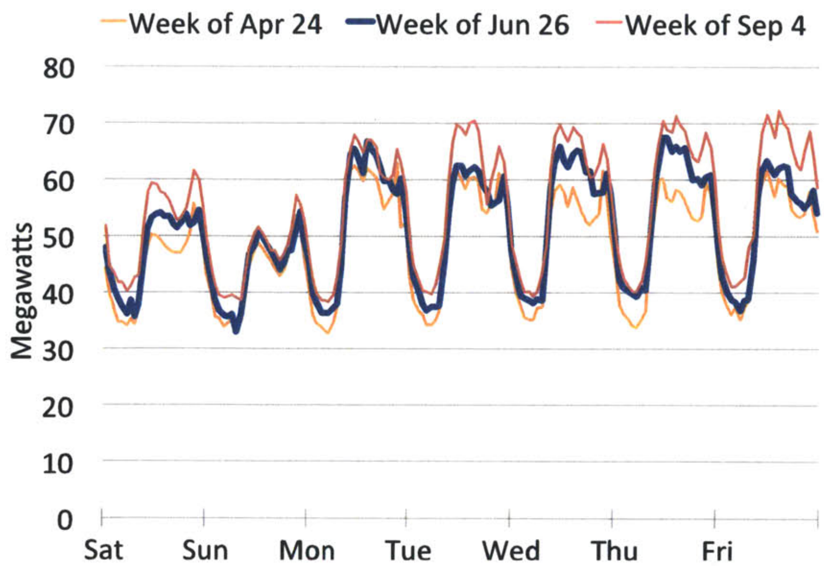


Figure 6-1: Hourly load shapes over one week on São Miguel

In this research, in which only 2018 is modeled, hourly load for selected weeks is grown uniformly from 2010 to 2018 to achieve 8% 8-year growth. The effects of this load growth assumption on peak load levels are shown in Table 6.1 and Figure 6-2. Notably, historical peak load on most of the Azores' islands was reached in 2010.[2] Consequently, the 8-year growth assumption for all islands results in significantly different 7-year (2011-2018) growth behavior between islands. In particular, smaller islands are estimated to have higher annual growth rates from 2011—a plausible outcome because smaller islands can be expected to have relatively greater energy growth potential.

Island	Peak Load 2010 (MW)	Peak Load 2011 (MW)	Assumed Growth 2010-2018	Peak Load 2018 (MW)	Implied Growth 2011-2018	CAGR 2011-2018
São Miguel	74.25	73.15	8.0%	80.19	9.6%	1.3%
Faial	9.42	8.97	8.0%	10.18	13.5%	1.8%
Flores	2.14	1.98	8.0%	2.31	16.8%	2.2%

Table 6.1: Historical and forecasted annual peak load growth

Whatever the actual load growth that is realized, the total load is unlikely to significantly alter the key insights of this research for energy storage and wind. The main effect of differences in total load is to increase or reduce the total operating costs

[2]For this research, hourly generation data was available through 2010, while annual peak load data was available through 2011. Subsequent generation and load patterns are not known at time of writing, and future load patterns are by necessity extrapolated from 2010 data.

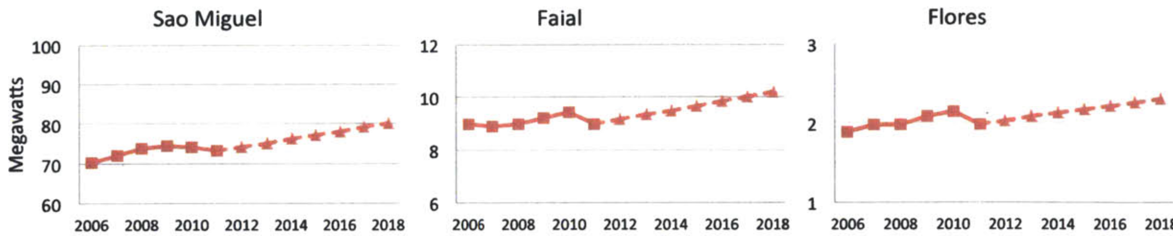


Figure 6-2: Historical and forecasted annual peak load

as a result of changes in total fuel consumption, as seen in the sensitivity analyses discussed in Section 7.7.

Fuel costs

As discussed in Section 5.5.2, limited information is available for the costs and exact types of fuel used for electricity generation in the Azores. Much less is known about fuel costs in the future. For this analysis, fuel oil on São Miguel and Faial is assumed to cost 15 €/MMBtu in 2018. That cost is on the high end of recent historical prices, however is not unlikely given expectations for high global oil prices to persist in years ahead. On Flores, where diesel fuel is burned for electricity generation, fuel costs are assumed to be 20 €/MMBtu.

In practice fuel costs might not be exogenous to other generation system factors—for example, at high wind penetrations, fuel costs might be higher because electricity generation from oil will decline and might lead to worse terms of trade for oil delivery to the islands than is already the case. Fuel costs will also vary between São Miguel and Faial, so the assumption of 15 euro does not represent relative differences between islands. As will be seen in the modeling results (Section 7.7), changes to the fuel cost assumption do not result in substantial differences in operating decisions or the applications of storage. Rather, changes to fuel cost will tend to scale with total operation costs, meaning higher fuel costs have a direct effect on the cost of electricity and the potential value of storage.

Generator specifications

Generating units on each island are modeled according to the assumptions in Tables 6.2–6.4. Plant information is collected from available sources; where details are not known for specific units on the Azores, approximate values are used based on the best judgement of the author.

Maximum and minimum output levels are determined to the best of the author's knowledge and from sources including the EurElectric NESIS Data Book and prior research of the Azores.[28, 48, 57] Compared to Table 5.1, some plants (e.g. Pico Vermelho and Ribeira Grande geothermal plants, and all hydro units) are de-rated to reflect actual generation levels observed in historical data.[6] For example, although 300 kW of hydro generation is reported to be installed on Faial, that capacity is not modeled because historical generation from hydro has been much less. Minimum output levels of renewables are set based on the range of output from historical data and to limit potential curtailment of geothermal plants.[3]

Plant	Number of Units	Heat Rate (Btu/kWh)	VOM (€/MWh)	Max (Min) Gen (MW)	Startup Cost (€)	Ramp Rate (MW/hr)	Min Up Time (Hrs)
MaK ICE	4	10,400	5	7.7 (3.85)	150	120	1
Wärtsilä ICE	4	8100	5	16.8 (8.41)	150	120	1
Pico Verm.	1	–	–	11.0 (10.0)	10,000	5	6
Rib. Grande	1	–	–	12.0 (10.0)	10,000	5	6
Hydro	1	–	–	2.25 (1.0)	10,000	2	6

Table 6.2: Generator performance assumptions for São Miguel

Plant	Number of Units	Heat Rate (Btu/kWh)	VOM (€/MWh)	Max (Min) Gen (MW)	Startup Cost (€)	Ramp Rate (MW/hr)	Min Up Time (Hrs)
ICE Units	6	8100	5	2.5 (1.0)	150	120	1
Hydro	1	–	–	0.1 (0.0)	10,000	1	6

Table 6.3: Generator performance assumptions for Faial

Plant	Number of Units	Heat Rate (Btu/kWh)	VOM (€/MWh)	Max (Min) Gen (MW)	Startup Cost (€)	Ramp Rate (MW/hr)	Min Up Time (Hrs)
ICE Units	4	8100	5	0.575 (0.2)	150	120	1
Hydro	1	–	–	0.5 (0.0)	10,000	1	6

Table 6.4: Generator performance assumptions for Flores

Heat rates are not known for particular plants in the Azores, and therefore are modeled as representative values for ICE performance. On São Miguel, the Wärtsilä units' heat rate roughly corresponds to a 42% plant efficiency, as reported for heavy oil units on the island of Cyprus.[4] The MaK units are older and and therefore assumed to have a higher heat rate; 10,400 is the average oil-burning ICE heat rate reported by the EIA for U.S. plants in 2011.[84] Faial and Flores each have a single

[3]Likewise, the startup cost on geothermal and hydro units is set artificially high in order to prevent these units from cycling on and off, thus mimicking must-run generator types. The costs are never imposed in reported model results because the units do not cycle off.

ICE generator model that are believed to all be operated in similar fashion as each other; for lack of available information, these are assumed to have the same heat rate as modeled for the São Miguel Wärtsilä units.

Variable operation and maintenance (VOM) and startup costs for ICE units are adopted from prior modeling work of São Miguel[28], while ramp rates are from [14]. Startup costs for geothermal and hydro units is intentionally set very high to prevent the model from cycling these units on and off; as a result, on/off cycling is avoided in the model and the reported results never include this cost. Minimum down time is assumed to be the same as minimum up time for all units.

Renewable resources are modeled as having zero operating costs to reflect costs as experienced by the EDA utility, which aims to maximize available renewable generation then must pay independent power producer (IPP) subsidiaries of EDA that operate those plants. Geothermal generation on São Miguel is payed according to a power purchase agreement (PPA), while wind and hydro generation are paid according to Portuguese national feed-in-tariff rates. In this analysis, feed-in-tariff and PPA costs are imposed on these resources *ex post* to unit commitment modeling, according to the level of output each of these resources is scheduled to generate. The assumed variable costs for renewable generation are shown in Table 6.5, and are based on Table 14 of da Silva (2013) and IEA reports for Portuguese energy policy.[28, 85][4]

Generation Type	Contract Type	Cost (€/MWh)
Geothermal	Power Purchase Agreement	84
Hydro	Feed-in Tariff	75
Wind	Feed-in Tariff	74

Table 6.5: Variable cost of renewable energy from PPAs and feed-in tariffs

Installed wind capacity and wind shapes

Each island is modeled for a set of increasingly larger installed wind capacity scenarios, beginning with the current wind capacity on the island. Wind capacity scenarios approximate possible wind expansion scenarios for each island, up to a level that achieves the Azores' 75% clean energy target. As seen from the Faial model results, however, this proves difficult in a case where there is currently no other renewable

[4]Terms of PPAs and feed-in tariffs are based on the author's best understanding of current EDA practice. Limited information was available to confirm the specific operating decisions and financial agreements of EDA.

generation other than wind—even where wind capacity is more than 150% of island peak load, as in the "Very Large Expansion" scenario. Modeled wind capacities are shown in Table 6.6.

	São Miguel	Faial	Flores
Current Capacity	9 MW	1.8 MW	0.6 MW
Medium Expansion	30 MW	6.0 MW	1.0 MW
Large Expansion	50 MW	12.0 MW	2.0 MW
Very Large Expansion	70 MW	18.0 MW	3.0 MW

Table 6.6: Modeling scenarios for total wind capacity

Wind shapes are derived from 2010 historical wind generation data on Flores. Flores, which has two 300 kW wind turbines, is used because it has the most reliable historical wind data of the islands.[5] In reality every island has a unique wind profile and seasonal characteristics, but using wind shapes from a single island should be adequate for purposes of this analysis.

Weekly total wind generation levels on Flores were analyzed in order to understand the variability of wind during the year. Figure 6-3 shows the week-to-week variability in total wind generation, illustrating the wide range of wind output levels and no easily discernible seasonality of wind. Figure 6-4 shows a histogram of this data and illustrates the diversity of wind output between weeks, as well as the lack of a clear shape to the distribution.

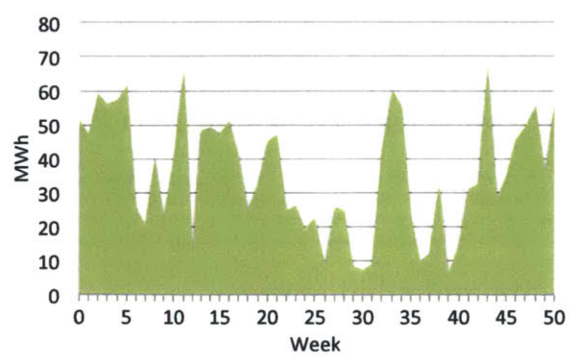


Figure 6-3: Weekly wind generation on Flores (2010)

From this weekly distribution, three weeks were selected to capture the range of wind capacity factors, as well as the intra- and inter-hour variability of wind. Each of

[5]The most recent available generation data is for 2010, when the Graminhais wind farm on São Miguel was not yet in operation. 2010 wind generation data is available for Faial, however the wind turbines on Faial turned off for 5.5 hours every night, making the data difficult to extrapolate from.

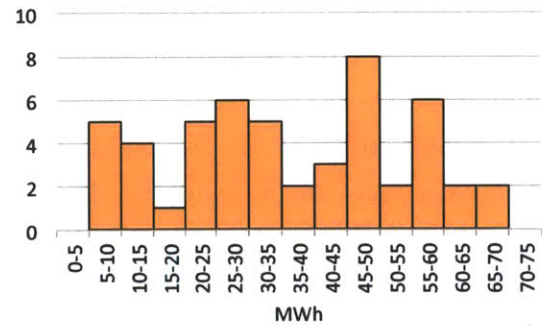


Figure 6-4: Histogram of weekly wind generation on Flores (2010)

the three wind shapes were modeled in every wind capacity scenario on each island, then a probability weighting was applied to the wind shapes in order to scale weekly results to annual cost and operation estimates. Table 6.7 summarizes the selected weeks, including the probability weightings that are applied for annual estimates.

	Dates	Total Wind Generation (MWh)	Average Capacity Factor	Modeled Probability
Low Wind	Aug 7–13	9.50	9.4%	25%
Medium Wind	Apr 3–9	40.25	39.9%	50%
High Wind	Dec 4–10	56.35	55.9%	25%

Table 6.7: Weeks selected for modeling of wind forecast

Figure 6-5 shows the hourly wind shape for the selected weeks (the y-axis is the capacity factor of wind). As can be seen, in addition to covering the range of total wind generation, the selected weeks provide three distinctly different shapes of wind across hours and days. Those include virtually no wind at the beginning of the low wind week, growing to small amounts at the end of the week; wide swings in wind from zero to almost full capacity in the medium week; and persistently high but variable wind in the high week.

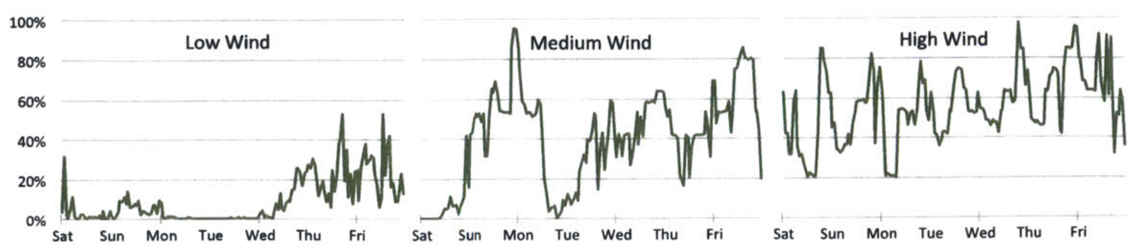


Figure 6-5: Hourly wind shapes of selected weeks for modeling of wind forecast

The probabilities assigned to these wind shapes are approximate representations for wind availability over a full year. The selection of probabilities was found by grouping the bins shown in Figure 6-4 into three sets—weeks for total wind generation of 5–25 MWh, 25–50 MWh, and 50–70 MWh—which in 2010 represented 29%, 47% and 24% of weeks, respectively. As can be seen from Table 6.7 the low wind week is at the extreme low end of the distribution of weeks, suggesting that this week might underweight the estimates to be low. This is offset, however, by a slightly lower probability assignment than was historically true (25% as opposed to the 29% from 2010), and selection of a "medium" week that is slightly above the 2010 average capacity factor of 35%. While it is true that these approximations will not capture the full diversity of wind patterns over the year, and will not precisely estimate the total generation levels over the year, on balance the selection of weeks and probability assignments should provide a fair representation of actual wind patterns.

Of note, wind generation is modeled as if it is supplied from a single wind farm—with a single wind shape and no "smoothing" that would result from geographic diversity of wind sites. Given that these are small islands with limited available wind sites, this is probably appropriate in most cases. Only on São Miguel, where greater site diversification is possible along different ridges and aspects of the island, might significant wind diversification be possible.

Reserve requirements

Separate reserve requirements are modeled for forecasted demand and for "committed wind". For all islands and in all scenarios, committed non-wind capacity must be able to provide up and down spinning reserves of 5% of forecasted load in each hour, in addition to 20% of committed wind.

Because reserve margins are partially based on what, in effect, is a control variable for expected future wind, wind curtailments can be viewed as a coarse control mechanism in advance of the operating hour (for example, by disconnecting some turbines), while in real-time there remains uncertainty for what level of output the remaining turbines will actually produce. This will lead to instances where it is economic to commit less wind than is forecasted in order to reduce the size of required reserves.

Storage specifications

Energy storage is modeled as a single storage unit without specification for technology type. Storage is modeled according to a limited number of key parameters—mainly energy capacity (MWh), power (MW), and efficiency—agnostic to what technologies can provide this level of service now or in the future. In this way, this research analyzes the effects on unit commitment and generation costs that are expected to result from different storage sizes and performance characteristics, and the results can be used to help inform storage technology choice and system design for island power systems.

In this analysis, maximum charging power is assumed to be equal to discharge power (i.e. storage units can store energy as fast as they can release it). Storage units are also assumed to have a minimum storage capacity—an operational restriction that is included to prevent deep discharge of storage units, which is known to cause performance degradation in some storage technologies (especially batteries). For computational simplification, the minimum storage capacity is set equal to the maximum charge and discharge rate. Specifically, by requiring the storage device to maintain the equivalent of one hour's worth of discharge potential, storage can be available for reserves up even when at its minimum capacity level, making the reserves formulation more tractable.

A diverse set of storage sizing dimensions are modeled in order to explore the effects of power and capacity levels on system costs and operations. Table 6.8 shows an example of the storage size assumptions as modeled for São Miguel. The range over which storage sizes are modeled is adjusted for each island (i.e. smaller storage sizes are modeled for smaller islands).

Maximum Power (MW)	Maximum Capacity (MWh)
1.0	10, 20, 40, 80, 120, 200
2.5	10, 20, 40, 80, 120, 200
5.0	10, 20, 40, 80, 120, 200
7.5	10, 20, 40, 80, 120, 200
10.0	10, 20, 40, 80, 120, 200
12.5	20, 40, 80, 120, 200
15.0	20, 40, 80, 120, 200
17.5	20, 40, 80, 120, 200
20.0	20, 40, 80, 120, 200
22.5	40, 80, 120, 200
25.0	40, 80, 120, 200
27.5	40, 80, 120, 200
30.0	40, 80, 120, 200
35.0	40, 80, 120, 200
40.0	40, 80, 120, 200

Table 6.8: Example of storage sizing assumptions

Roundtrip efficiency of storage is assumed to be 75% in all scenarios modeled. Different storage technologies have achieved a wide range of efficiency levels, and 75% is roughly in the middle to high end of this range.[41] Similar to the effects of heat rates and demand levels, small differences in the efficiency of storage will not significantly change the key insights of this analysis for the optimal sizing and uses of inter-hour energy storage. As efficiency improves, however, greater cost savings can be expected and the economic case for energy storage is stronger.

6.3.2 Model calibration

Model runs were compared to historical generation data in order to calibrate assumptions and validate the mathematical formulation. Figure 6-6 shows historical data on São Miguel for a week in 2010 (left panel) compared to the results of the model for the hourly load shape of the same week (right panel). While historical data is only available on an aggregated basis by power plant, the model results show generation dispatch by individual unit. As can be seen, the model captures the generation levels of the actual operating patterns fairly well, although the model does not give the specific hourly output levels of geothermal and hydro as occurred in the historical data. The week of December 4, 2010 is used for this calibration because the geothermal plants underwent a number of capacity updates in the course of 2010, and the higher output levels are needed for purposes of calibrating the model for future performance. This week also happens to include the 2010 peak load hour for São Miguel.

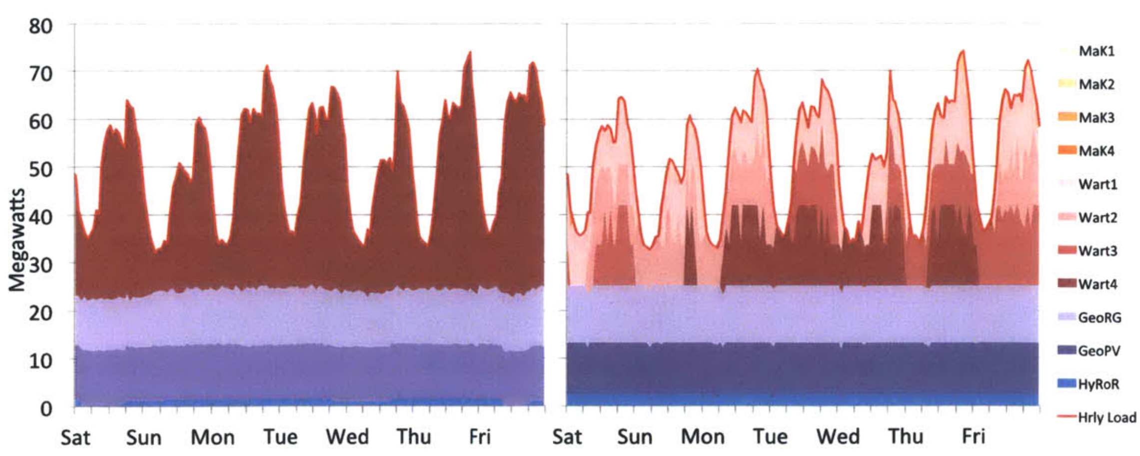


Figure 6-6: São Miguel historical generation compared to model results

Chapter 7

Results

Key results of this research are presented in the sections below. Results are organized by metric, with general discussion of the metric followed by results for each of the three islands. Results are described on a comparative basis for cases with and without the availability of energy storage. The analysis presented is for assumed demand levels in 2018, as well as other fuel cost and generator assumptions described in the previous chapter. The chapter concludes with a limited number of sensitivity analyses to explore how these results might change under different input assumptions.

7.1 Generation Dispatch

In addition to unit commitment decisions, the model determines the least-cost generation dispatch that meets all constraints over all hours of the week. Units are committed and dispatched in order to minimize costs for fuel consumption, variable operation and maintenance, and startup costs, while operating between minimum and maximum levels for stable load and meeting reserve requirements. As formulated for the Azores, the model favors generation from zero-cost renewable units (geothermal, hydro and wind), while minimizing expensive unit starts and fuel consumption of the ICE units. Even so, in some hours zero-cost renewables are forced to be curtailed in order to avoid cycling other units on and off and thus incurring startup costs, or where higher wind levels would require larger reserve levels be maintained. In the absence of energy storage, this entails high reliance on fuel-burning generation and—when installed wind capacity is large—heavy wind curtailment (or "spillage").

Figure 7-1 illustrates these effects from a single model run for one week on São Miguel with high wind availability. As shown, the hydro (upper-right panel) and geothermal units (Pico Vermelho and Ribeira Grande at lower-left) are dispatched at maximum output and operate as baseload generation. Despite their zero fuel and VOM costs, however, these plants are curtailed in some hours; the alternative option is to shut off and restart fuel units, which is more expensive than keeping the fuel units online and generating. Those fuel units—the four large Wärtsilä units and four smaller MaK units—operate both for baseload and on-peak load-following purposes. Finally, the large capacity of wind that is assumed to be installed in this scenario (30 MW) is available according to a highly variable pattern (shown in light green), yet not all of this wind is dispatched by the model (dark green). As described in the preceding methods chapter, this wind dispatch can be considered a preemptive decision to not commit a portion of wind turbines in order to reduce the expected level of total wind generation. Alternatively, fine-grained wind dispatch of this nature might be possible from advanced wind turbine models and system operator controls that allow "feathering" and pitch-control of wind turbine blades in order to actively manage how much power is extracted from available winds.

Figure 7-2 shows the generation dispatch results for the same load and wind scenario, but with energy storage now installed. In this case, at 200 MWh of capacity and 40 MW of power, energy storage is intentionally modeled to be oversized. The availability of energy storage eliminates the need for curtailment of hydro and geothermal, and nearly all wind curtailment. In addition, energy storage eliminates any need for the smaller MaK fuel units, and reduces the larger Wärtsilä units to mainly day-time peaking power plants. This indicates that the availability of storage might allow islands to mothball or completely retire some thermal generators that are currently used for limited peaking purposes—potentially saving significant fixed costs in addition to those variable operation and fuel costs that are modeled here. Hourly charging and discharging of storage is shown in the upper-right corner of Figure 7-2.

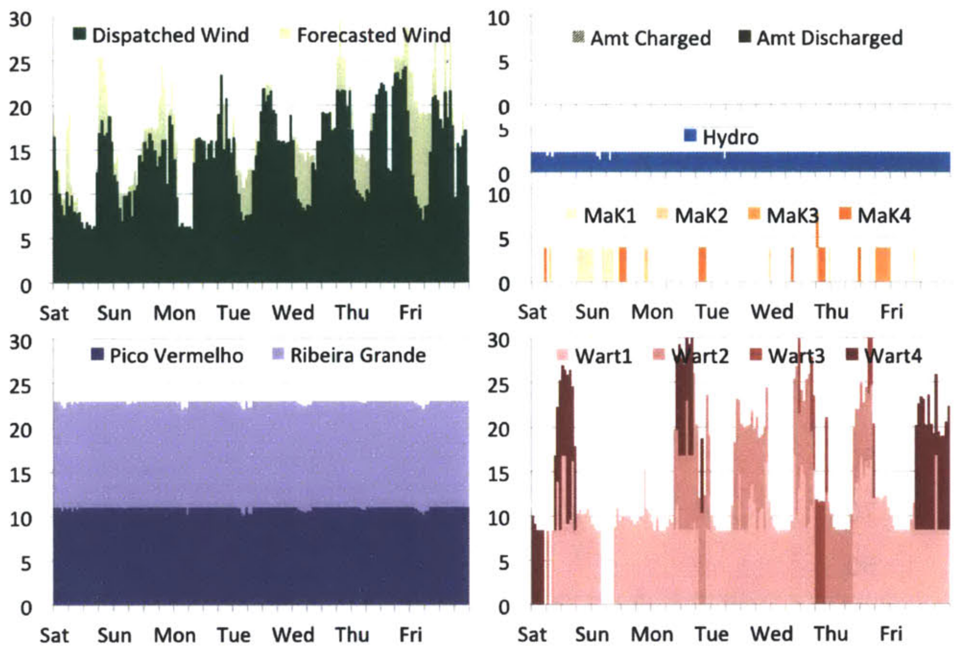


Figure 7-1: São Miguel generation dispatch without storage

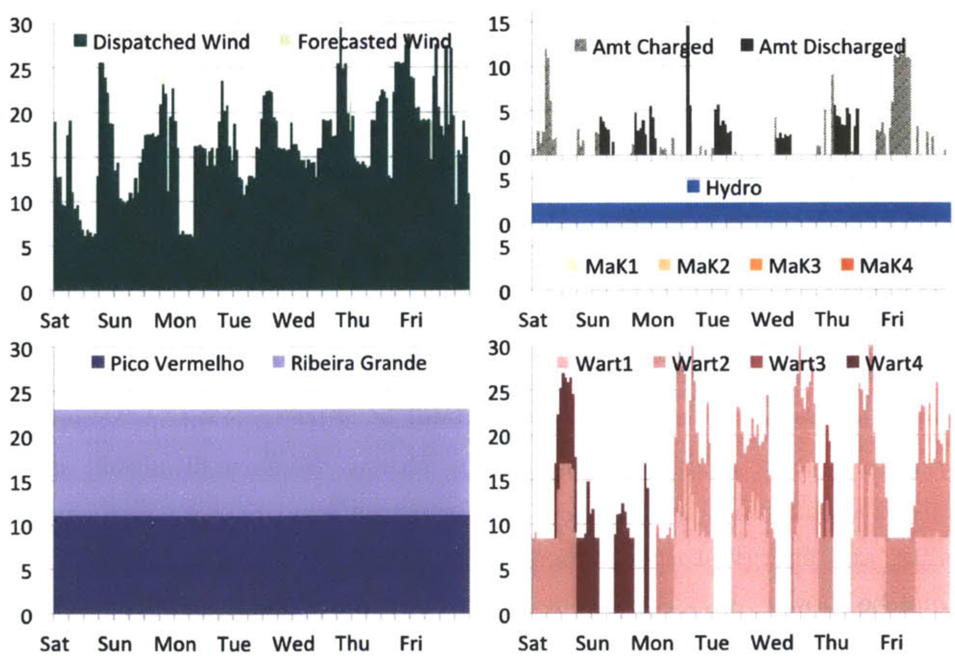


Figure 7-2: São Miguel generation dispatch with 40MW/200MWh of storage

Figure 7-3 shows the same results in an alternate format. Where Figures 7-1 and 7-2 emphasize the expected hourly dispatch of individual power plants and units, this representation shows how those output levels combine to serve total demand. Figure 7-3 also illustrates how storage is utilized across the full week. Interestingly, storage is not strictly charged in overnight off-peak hours then discharged during the daytime for peak-shaving purposes. Rather, charging and discharging decisions are made according to the hour-by-hour least-cost uses, which in some cases means discharging during off-peak hours and charging on-peak. Wind curtailment is shown in Figure 7-3 by the green line that dips negative in a small number of hours.

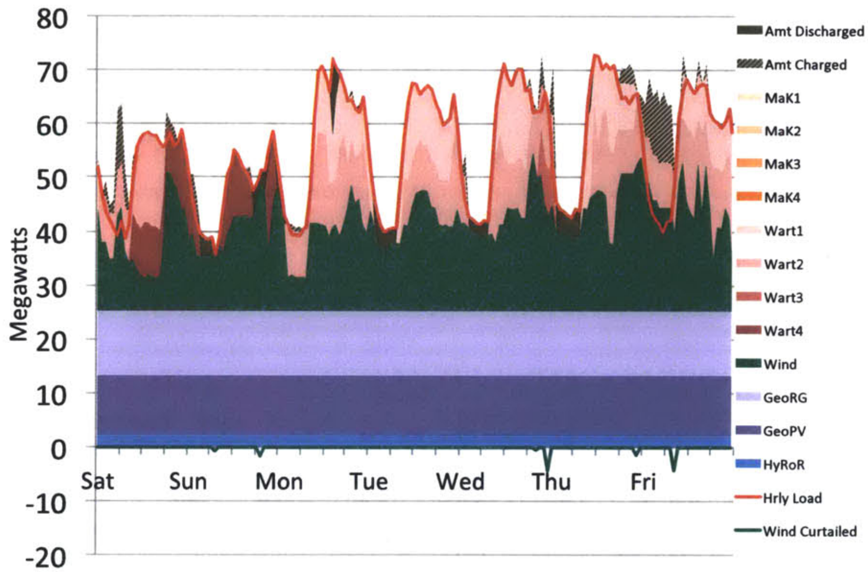


Figure 7-3: São Miguel generation dispatch with 40MW/200MWh of storage

The following figures show similar information for Faial and Flores. Model runs are selected to particular effects on each island in order to compare where different effects dominate and to highlight interesting results. Because hundreds of scenarios were run for each island—including a wide range of wind penetrations, hourly wind availability, and energy storage dimensions—the detailed results for every modeling run cannot be shown. Also, due to the highly deterministic nature of the model, which optimizes for the specific hourly load and wind levels in each hour, the precise results for generation levels and storage charge/discharge decisions will vary. Nonetheless, general observations can be made from individual runs that will tend to be true for other similar cases. In subsequent sections, results are collected for similar wind and storage scenarios in order to generalize results across scenarios.

Figure 7-4 shows the hourly commitment and dispatch results for a week on Faial with 12 MW of wind capacity and medium wind capacity factor. This figure illustrates a case with very high wind penetration and high utilization of storage. Faial also lacks significant capacity of non-wind renewable generation (exception being a small amount of hydro), leading to wide swings in fuel generation. Even with abundant energy storage available in this scenario (in this case, 80 MWh storage capacity and 6 MW of storage power is modeled), fuel generation from ICE units is relied upon for generation in low-wind hours, as well as maintenance of reserve requirements to supplement energy storage. It is also notable that energy storage is not utilized strictly for charging in overnight off-peak hours and discharging during peak hours, as is often assumed to be the best value for storage; rather, storage is optimized across all hours to achieve least-cost operations, which can sometimes require discharging off-peak or charging during peak load hours. Finally, Figure 7-4 illustrates the effect of circular lag operators, which require the storage charge state at the end of the week to be the same as at the start of the week; in this case, storage is discharged in the early hours of the week then must charge in later hours to replenish lost energy.

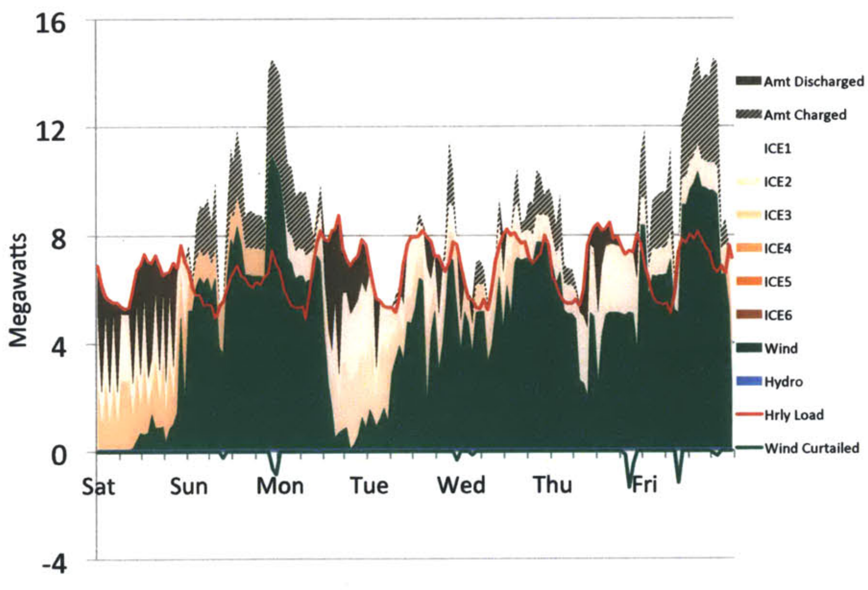


Figure 7-4: Faial generation dispatch with 6MW/80MWh of storage

Figure 7-5 shows generation dispatch on Flores for a week with 3 MW of installed wind but low wind availability (in this case, 2.5 MWh storage capacity and 250 kW of storage power is modeled). Due to the very limited wind available in the first part of the week—despite wind capacity that is more than 50% greater than total system load—diesel-burning ICE generators provide the majority of electricity in most hours. The availability of hydro generation, however (modeled at the average annual output of 0.5 MW), enables more renewable generation than wind alone can provide. In the limited number of hours with high wind availability, some wind is curtailed, as well as some hydro generation. In this case, energy storage is capacity-limited over the week, depleted from full charge to close to minimum charge levels; as will be discussed later in this chapter, a limited size storage installation such as this might be optimal due to high capital costs of storage and diminishing returns on storage size.

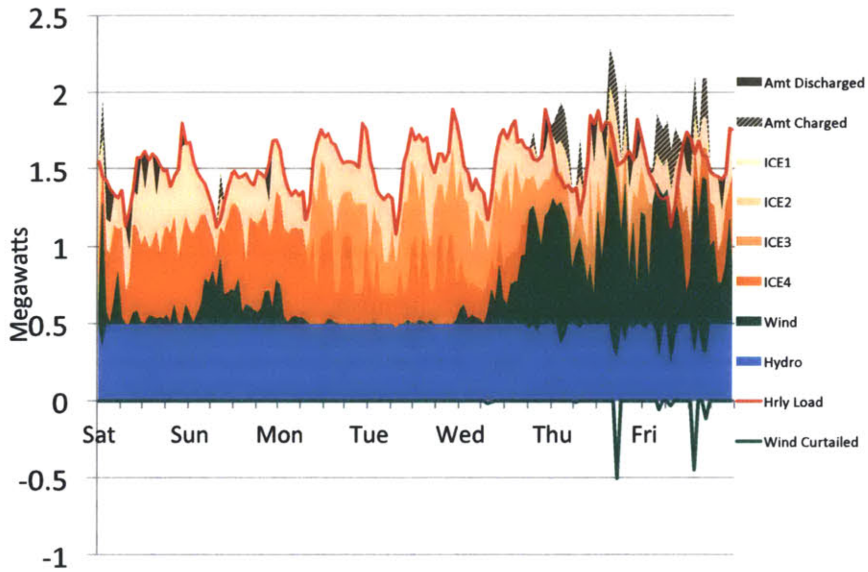


Figure 7-5: Flores generation dispatch with 250kW/2.5MWh of storage

7.2 Cycling of generation units

One of the more significant operational benefits from bulk storage is to reduce the number of starts and stops of generation units. The availability of storage allows the system operator to avoid shutdown of units in off-peak hours, only to restart the same or another unit a short time later, because storage units can be charged with the excess generation above demand in those hours. Likewise, in some peak hours, units do not need to be turned on to meet peak demand only to be turned off a short time later, because storage can discharge at those times. Even in the absence of high penetration of wind capacity, storage can drastically reduce the expensive on/off cycling of thermal units, thereby offering operational benefits and potential cost savings.

São Miguel

Figure 7-6 compares the number of ICE unit starts on São Miguel across different levels of installed wind capacity and storage power, estimated over a full 52-week year.[1] As shown, energy storage reduces the number of starts of generating units in all cases, including a reduction from approximately 800 to under 500 starts on the current system of 9 MW of installed wind. The reduction is more dramatic at higher levels of wind penetration, where the availability of storage can reduce ICE unit starts from around 1,500 per year to below 1,000. At every level of installed wind capacity, there is a diminishing return on unit start reductions as storage power increases, and storage reaches "saturation" sooner at lower levels of wind capacity.

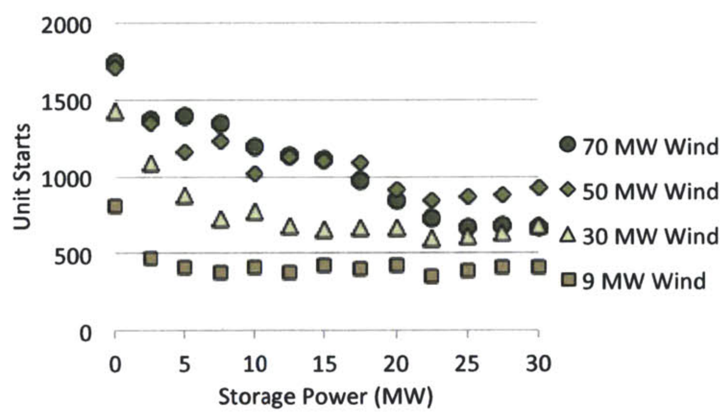


Figure 7-6: Annual ICE unit starts on São Miguel

Notably on São Miguel, the majority of eliminated unit starts occur on the smaller, more expensive MaK units. In the 9 MW wind case, the MaK units are completely eliminated from operation with the availability of even 1 MW of storage. This offers the possibility to mothball some of these units in order to save on annual fixed O&M costs of keeping the units in service. At higher wind penetrations, however, the MaK units are utilized according to the model, suggesting that the units offer valuable operational flexibility as wind capacity increases. Even so, based on a sensitivity

[1]Because every storage power (MW) was modeled for a range of storage capacities (MWh), these results reflect the average number of ICE unit starts at each level of storage power for a range of storage capacities. Across the range of storage capacity levels modeled for each storage power, the range of total starts is relatively narrow, thus this averaging is considered a fair approximation.

analysis for a case with 50 MW of wind and without the MaK units available, the model shows that demand can be served by the remaining Wärtsilä ICE units (plus geothermal and hydro capacity) in all hours for each of the three wind shapes. This is true even for a system without any energy storage. Variable operation costs are slightly higher in these cases without the MaK units, however this might be offset by a reduction in annual fixed O&M costs if the units are mothballed. In any case, these results are merely suggestive and do not consider important factors such as network stability and voltage control; careful study and contingency analyses would be needed before any decisions are made to reduce thermal capacity.

Faial

Figure 7-7 shows the number of ICE unit starts required on Faial over one year. On the existing Faial power system, where electricity is supplied exclusively by six fuel-burning ICE units plus a 1.8 MW wind farm and limited hydro, the model results indicate that fuel units should never be stopped or started—at all wind weeks modeled, four of the six ICE units can run from the first to the last hour of the week while operating between maximum and minimum generation levels and providing adequate spinning reserves. Furthermore, energy storage does not change the number of ICE unit starts and stops on the current Faial system. This result is attributable to the high cost of unit startups: at the current wind penetration, it is more economic to curtail small amounts of wind than to shut-down a unit and restart it—even when large amounts of storage are available to shift energy across hours.

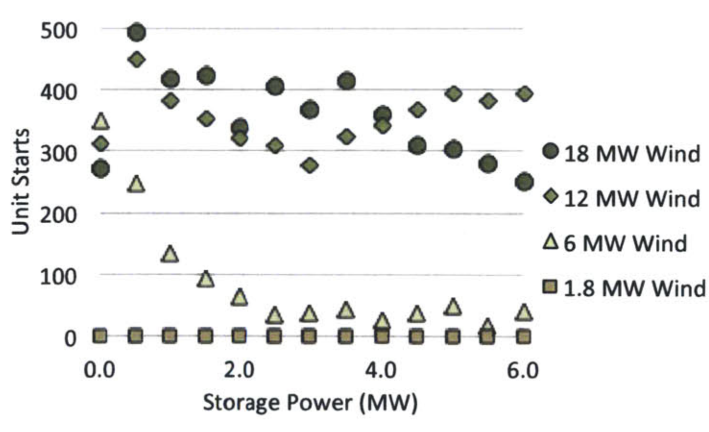


Figure 7-7: Annual ICE unit starts on Faial

Under a scenario of 6 MW installed wind, the effect is much different. Without storage, more than 300 ICE unit starts are needed during the year to provide least cost generation dispatch. The number of starts declines to below 50 as larger amounts of storage is added, until the estimated starts levels off above 2.0 MW of storage. At that point, the system is saturated with energy storage that it is not able to utilize. At even higher levels of installed wind capacity—12 and 18 MW—the effect of energy storage on unit starts is less conclusive. The estimated number of starts at each level of storage power oscillates between around 300 and 500 per year. At these high penetrations—where installed wind is larger than island peak demand—the large amount of wind appears to overwhelm the system and the thermal units are relied upon for frequent starts and stops to balance demand.

Flores

Figure 7-8 shows similar results for Flores.[2] A small reduction in ICE unit starts is found for the current power system of four ICE units plus 600 kW of wind and 500 kW of expected hydro. The effect is more apparent at 1 MW of installed wind capacity, when starts decline from almost 200 per year to around 50 after 200 kW of storage power is added. At higher penetrations of wind (2–3 MW, which exceeds island peak load), the number of ICE unit starts remains above 200 per year despite adding energy storage.

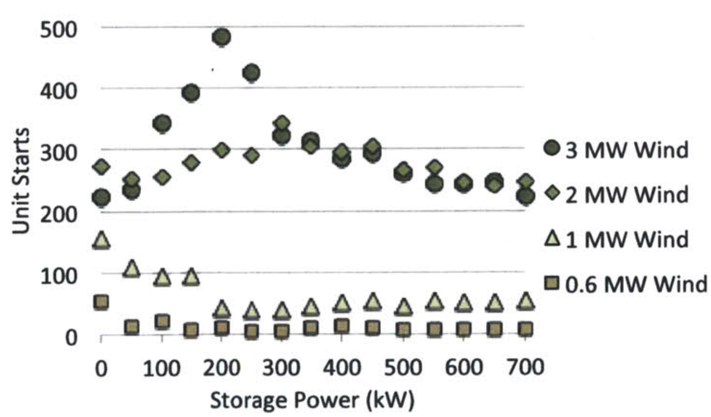


Figure 7-8: Annual ICE unit starts on Flores

[2]Note the kW-scale storage on Flores' charts, compared to MW on the other islands.

7.3 Renewable energy generation

As storage size increases, larger amounts of variable renewable generation are economically justified on island power systems, and more of the available wind power can be harnessed for electricity generation rather than spilled (i.e. fewer curtailments). This suggests that energy storage can be helpful—and in fact might be required—to meet high clean energy targets such as the Azores' goal of 75% renewable generation by 2018.

7.3.1 Wind curtailments

Energy storage has a direct impact on reducing the amount of wind curtailment on islands due to the ability to shift energy across hours from when it is generated to when there is demand, as well as the opportunity to eliminate expensive ICE unit starts, which can make wind-following by those ICE units expensive and thus lead to curtailment decisions. The following tables show the effects of energy storage on wind curtailment. At each wind capacity level, the estimated annual curtailments are shown in total MWh, as well as the percentage of available wind at that installed capacity that is estimated to be spilled.

São Miguel

Table 7.1 shows estimated wind curtailments on São Miguel. At the current wind capacity of 9 MW, storage eliminates some wind curtailment that is expected under the case without storage, although there is not much curtailment to begin with. At higher wind penetrations, increasing amounts of storage are needed to avoid significant wind curtailment.

Storage Power	9 MW Wind		30 MW Wind		50 MW Wind		70 MW Wind	
(MW)	MWh	Pct.	MWh	Pct.	MWh	Pct.	MWh	Pct.
0	1,015	4%	13,420	14%	58,055	37%	114,303	51%
5	436	2%	2,619	3%	31,917	20%	81,539	37%
10	413	1%	1,543	2%	17,169	11%	60,194	27%
15	263	1%	994	1%	10,235	6%	47,205	21%
20	416	1%	1,311	1%	9,974	6%	42,288	19%
25	261	1%	925	1%	6,607	4%	34,399	15%
30	482	2%	835	1%	7,055	4%	34,327	15%

Table 7.1: Estimated annual wind curtailments on São Miguel

Faial

Table 7.2 shows the same results for Faial. At the current wind capacity of 1.8 MW, storage eliminates the very small amount of curtailment that is expected under the case without storage, but in reality has a negligible impact. Similar to São Miguel, increasing amounts of storage are needed at higher wind penetrations to avoid significant wind curtailment. Even so, at the highest levels of installed wind—greater than expected peak load in 2018—some level of curtailment is unavoidable.

Storage Power	1.8 MW Wind		6.0 MW Wind		9.0 MW Wind		12.0 MW Wind	
(MW)	MWh	Pct.	MWh	Pct.	MWh	Pct.	MWh	Pct.
0.0	57	1%	1,532	8%	15,439	41%	33,053	58%
1.0	0	0%	303	2%	10,032	26%	26,601	47%
2.0	1	0%	113	1%	6,241	16%	21,730	38%
3.0	0	0%	14	0%	3,923	10%	18,351	32%
4.0	0	0%	24	0%	3,180	8%	16,141	28%
5.0	1	0%	53	0%	3,029	8%	15,453	27%
6.0	0	0%	29	0%	1,762	5%	13,361	23%

Table 7.2: Estimated annual wind curtailments on Faial

Flores

Table 7.3 shows similar results for Flores. In this case, curtailments remain very limited even if wind capacity is expanded to 1 MW, however above that level storage is needed to avoid excessive curtailments.

Storage Power	0.6 MW Wind		1.0 MW Wind		2.0 MW Wind		3.0 MW Wind	
(MW)	MWh	Pct.	MWh	Pct.	MWh	Pct.	MWh	Pct.
0.0	59	3%	52	2%	792	12%	3,241	34%
0.1	15	1%	17	1%	613	10%	2,906	31%
0.2	27	1%	9	0%	445	7%	2,543	27%
0.3	5	0%	13	0%	300	5%	2,070	22%
0.4	5	0%	17	1%	198	3%	1,705	18%
0.5	6	0%	15	0%	196	3%	1,757	18%
0.6	6	0%	14	0%	220	3%	1,836	19%
0.7	6	0%	15	0%	192	3%	1,748	18%

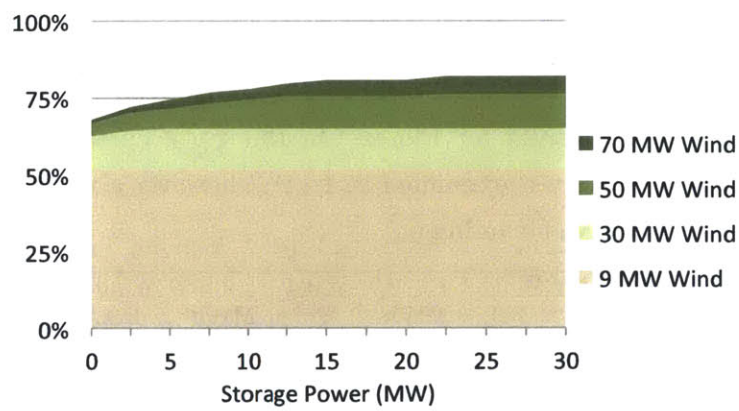
Table 7.3: Estimated annual wind curtailments on Flores

7.3.2 Total renewable generation

The following figures show estimated percentages of total generation from renewable sources over the full year, based on the probabilistic weighting of wind shapes for each installed wind capacity scenario.[3] Each island chart shows the estimated renewable energy from the existing generation mix on that island, plus scenarios for increasing levels of wind penetration in an attempt to achieve the 75% clean energy target.

São Miguel

In the case of São Miguel, the current generation mix is already about 50% renewable energy due to the two geothermal power plants, 9 MW of wind, and small hydro plants. This result corresponds to recent operations on São Miguel.[50] Energy storage is not found to provide any significant boost to clean energy generation for the current power system on São Miguel. The 75% clean energy target, however, is only reached under a scenario of very high wind penetration (50–70 MW installed capacity), with some energy storage required to limit wind curtailments and achieve the target. Figure 7-9 illustrates these results and includes a table above the figure as a reminder of the renewable capacity that underly the results for each wind penetration scenario.



Renewable Capacity as Modeled for São Miguel

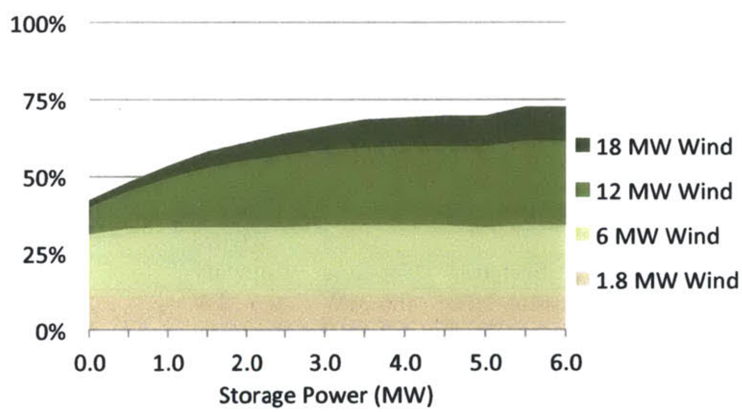
Scenario	Wind Capacity	Geothermal Capacity	Hydro Capacity
Current Mix	9 MW	23 MW	2.25 MW
Medium Wind	30 MW	23 MW	2.25 MW
High Wind	50 MW	23 MW	2.25 MW
Very High Wind	70 MW	23 MW	2.25 MW

Figure 7-9: Renewable generation impact from storage on São Miguel

[3]Similar to unit starts, these results are for the average percentage of renewable generation at each level of available storage power, averaged across multiple energy capacity scenarios. As for unit starts, the range of clean energy percentages is relatively narrow within each storage power set, thus this averaging is considered a fair approximation.

Faial

Figure 7-10 shows the expected clean energy impact from storage for Faial. On the existing network, wind can provide around 10% of total energy demand and storage does nothing to increase that share. Similarly, 6 MW of installed wind would provide around one-third of total demand, however storage does very little to increase that amount. This result changes at very high penetrations of wind. At 12 MW of wind capacity without storage, only 40% of energy can be supplied by wind due to heavy wind curtailment, but that share increases to around 60% above 3 MW of storage. Likewise, 18 MW of wind capacity provides little more actual generation without storage, but can serve 70% or greater when storage is installed. Even so, at these extremely high levels of installed wind capacity, there is a diminishing effect of storage on increasing clean energy generation, and the 75% target would require even larger amounts of wind and or storage than was modeled here (and perhaps than is realistic on Faial, where peak load was less than 10 MW in 2010).



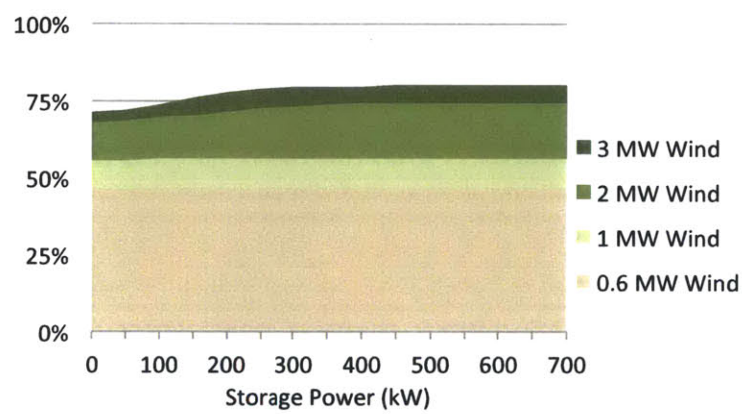
Renewable Capacity as Modeled for Faial

Scenario	Wind Capacity	Hydro Capacity
Current Mix	1.8 MW	0.1 MW
Medium Wind	6.0 MW	0.1 MW
High Wind	12.0 MW	0.1 MW
Very High Wind	18.0 MW	0.1 MW

Figure 7-10: Renewable generation impact from storage on Faial

Flores

Energy storage has a limited effect on increasing renewable generation on Flores. On the existing system, with 600 kW of wind capacity and average hydro output of 500 kW, clean energy sources can supply nearly half of annual electricity demand. That amount increases to about 55% with an additional 400 kW of wind, but storage has a negligible effect on total renewable generation at this wind capacity. At 2 MW of wind, however, energy storage enables renewable generation to increase from approximately 68% to 74%, with storage saturation reached around 250 kW. 3 MW of wind and at least 150 kW of storage is needed to achieve the 75% clean energy target; total clean energy increases to around 80% at that wind capacity with 400 kW of storage.



Renewable Capacity as Modeled for Flores

Scenario	Wind Capacity	Hydro Capacity
Current Mix	0.6 MW	0.5 MW
Medium Wind	1.0 MW	0.5 MW
High Wind	2.0 MW	0.5 MW
Very High Wind	3.0 MW	0.5 MW

Figure 7-11: Renewable generation impact from storage on Flores

7.4 Annual operating costs and savings

Based on the model results for different sized storage installations, cost savings from storage can be calculated. These results include additional variable costs for renewable generation, calculated at known feed-in tariff and power purchase agreement rates and charges according to unit dispatch results from the unit commitment model. Operational cost savings are calculated for every wind and storage combination and for each of three weekly wind shapes, then probabilistically combined to find an annual estimate. Total annual costs are then compared to the estimated costs for the zero-storage case in order to arrive at an estimated cost savings attributable to storage.

São Miguel

Figure 7-12 shows the evolution of operating cost savings available from storage on São Miguel. In this figure, costs savings from storage are larger as wind penetration increases.[4] Cost savings also increase as storage size increases. The increasing savings from storage are attributable to the greater availability of storage for reserves (reduced need for expensive fuel units and fewer unit starts) as storage becomes larger, and the ability for storage to reduce renewables curtailment, thus enabling oil generation to be replaced with less expensive renewables.

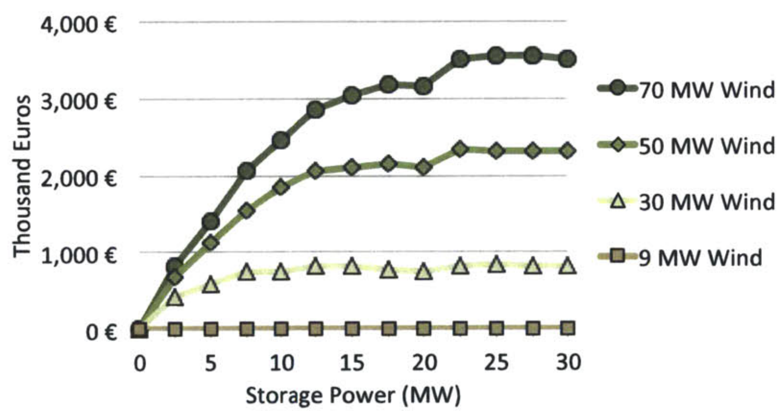


Figure 7-12: Annual operating cost savings from storage on São Miguel

At higher wind penetration levels, the cost savings from storage show a diminishing return as the storage unit becomes over-sized for the level of wind penetration and the excess storage is not utilized. The level at which storage becomes oversized is higher for higher wind penetrations (for example, storage becomes oversized around

[4]On the current system of 9 MW wind, storage does not demonstrate any cost savings. This finding is partly attributable to the assumptions of the unit commitment model, in which renewable sources are considered to have zero cost for purposes of unit commitment and dispatch, only to have those costs imposed *ex post* in the form of feed-in tariffs or PPAs. Inclusion of those costs in the unit commitment model would likely result in somewhat different utilization of renewables.

10 MW power in the 30 MW wind case, whereas 25 MW of storage still offer potential savings in the 70 MW wind case).

Faial

Figure 7-13 shows estimated operational savings on Faial. The general shape of the costs savings is very similar as seen on São Miguel. In this case, storage becomes oversized at just 1 MW power in the 6 MW wind case, while 6 MW of storage offer potential savings in the 18 MW wind case.

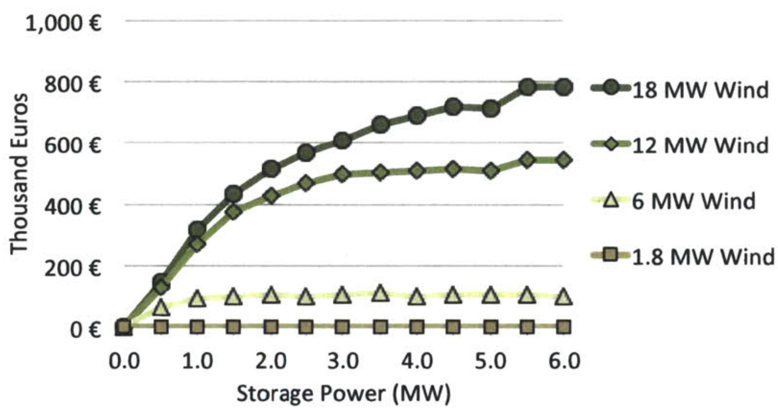


Figure 7-13: Annual operating cost savings from storage on Faial

Flores

Figure 7-14 shows cost savings from storage on Flores. Interestingly, cost savings from storage are limited on Flores at low power levels, then demonstrate a steep increase around 200 kW power before leveling off. There are also potential cost savings from adding storage to the existing generation portfolio: 10–12 thousand euro per year can be saved from installation of energy storage with greater than 200 KW rated power.

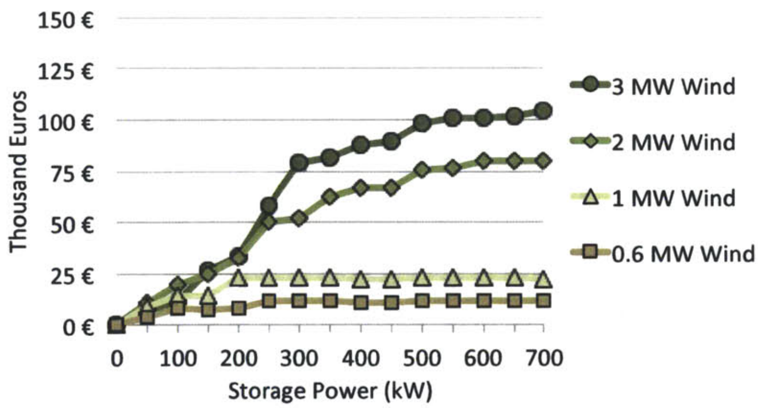


Figure 7-14: Annual operating cost savings from storage on Flores

7.5 Sizing of Storage

Based on model runs for a large range of storage installation sizes—sized for both storage capacity (MWh) and power (MW)—an optimal size of storage is investigated for each island. This investigation can be carried out for any island power system configuration, including different wind penetration levels. In this discussion, storage size is analyzed for a level of installed wind capacity that is needed to reach the 75% clean energy target (or, in the case of Faial, the largest wind capacity investigated).

São Miguel

Figure 7-15 shows the estimated annual savings from storage on São Miguel, assuming installed wind capacity of 70 MW. This 3-dimensional topographic chart is based on the results from 75 model runs, each assuming a different configuration of available storage capacity and power—ranging from 1 MW power and 10 MWh capacity at the smallest to 40 MW and 200 MWh at the largest. The intermediate sizes between these two extremes capture a range of power and capacity amounts, including different ratios of power to storage capacity.

As can be seen in Figure 7-15, there is a significant savings from storage as the charging and discharging power increases—from less than half a million euro per year to nearly 4 million euro. On the other hand, there is limited improvement in savings from increases in storage capacity; at fixed power levels, the cost savings are quite flat across different capacity levels, with the exception of some diminished savings at the smallest-sized capacities. Notably, there is a diminishing return to operating cost

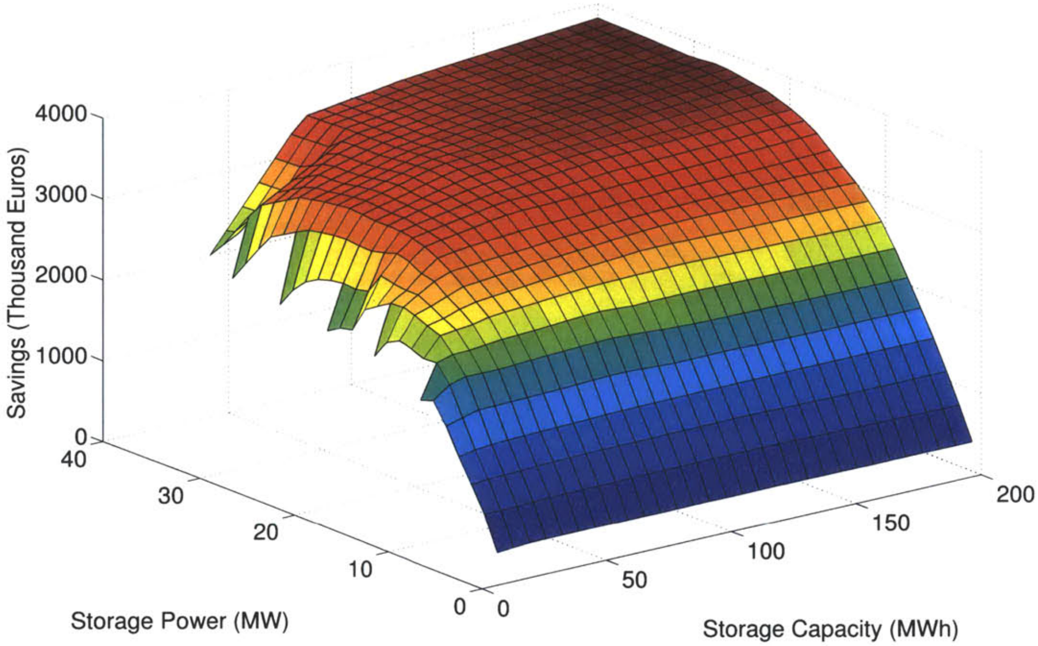


Figure 7-15: Savings by size of energy storage on São Miguel with 70 MW of wind

savings as storage power increases, and indeed the the savings "plateau" around 25 MW storage power, after which storage size exceeds system needs.

Faial

Figure 7-16 shows a similar plot for Faial with 12 MW of installed wind. Again, cost savings from increased storage power are significant, while increasing storage capacity provides limited operating savings (although slightly better than on São Miguel). On Faial under this wind penetration scenario, savings from increased storage power level off around 2–3 MW.

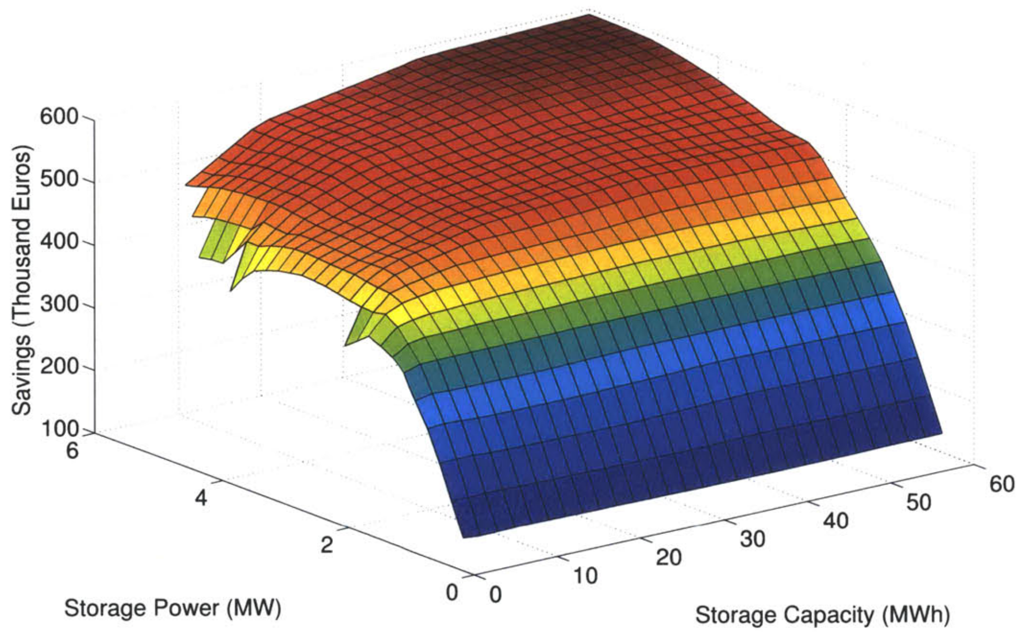


Figure 7-16: Savings by size of energy storage on Faial with 12 MW of wind

Flores

Figure 7-17 shows estimated savings from storage on Flores given a scenario of 2 MW of installed wind. Interestingly, although the same general shape persists as for other islands, Flores appears to offer increased savings from higher storage capacity amounts. This might be due to the higher variability in net load experienced on the smaller island—due to more significant hour-to-hour swings in electricity demand—for which energy storage is well-suited to smooth out. In Flores' case, operating costs savings level off above 350 kW power and 1 MW storage capacity, although small increases in savings persist up to the largest storage unit shown (700 kw; 2.5 MWh).

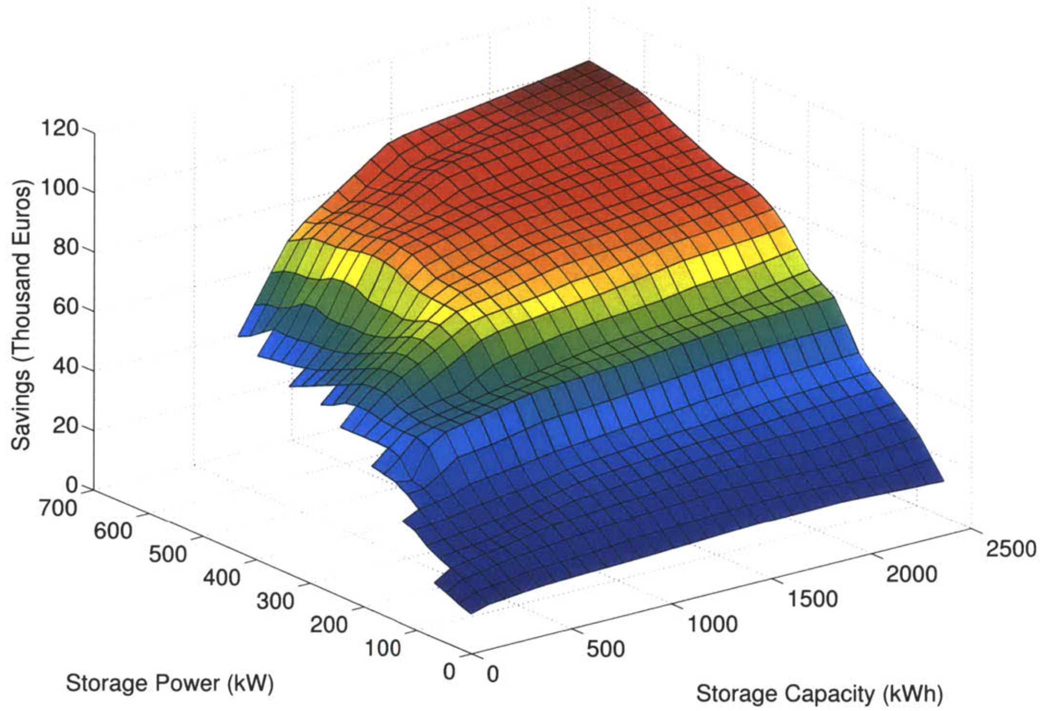


Figure 7-17: Savings by size of energy storage on Flores with 2 MW of wind

7.6 Value of Storage

In order to provide insight into the value of storage at different sizes and wind penetrations, Figures 7-18 through 7-20 show the same annual savings from storage as seen in Section 7.4, now overlaid on a range of possible investment costs of storage. On each island, there is an economic case for storage as long as the expected annual savings from storage are greater than the cost of storage (i.e. the green line is above the expected storage cost). As seen in each figure, the case for storage is strongest at higher wind penetrations, however there is large uncertainty for future costs of storage. At the high end of the range, investment costs in storage are not expected to be recovered from savings in operating costs.

The high and low ends of storage investment costs are based on a per-kW measure, roughly corresponding to the range of costs from EPRI 2010.[41] For all islands, the high cost corresponds to \$4,000/kW overnight capital costs for storage, or 3,000 €/kW at a 1.00:0.75 dollar-to-euro exchange rate. The low cost corresponds to the U.S. Department of Energy's long-term cost target for storage of \$1,250/kW, or roughly

940 €/kW. The cost of storage is amortized to an annual cost assuming a 15-year lifetime and 5% interest rate. This analysis assumes no operating costs from storage, and storage investment costs are assumed to scale linearly with size; in reality, some ongoing operation and maintenance costs are likely, and investment costs might be expected to change with size due to economies of scale—both of which would effect these findings.

For cases where savings are greater than costs, a value of storage can be calculated as the difference between estimated savings and storage cost at each respective storage size. In this way, an optimal storage size is found where the difference between savings and costs is greatest. However, due to the uncertainty in storage costs, as well as the preferred level of wind capacity on each island, optimal storage sizes remains unknown at this time. To illustrate these effects, each figure in this section is accompanied by a table that shows how the optimal size of storage changes over the range of anticipated storage costs. As these tables make clear, storage installations should be sized larger if the cost of storage is less because the potential value of storage becomes larger as storage costs decline. Likewise, larger storage installations are preferred at higher wind penetrations.

São Miguel

As seen in Figure 7-18, storage does not make economic sense on São Miguel in low wind penetration scenarios (i.e. the annual cost of storage is above the operating cost savings), however storage might be economically justified in high wind penetration scenarios. In particular, if storage costs are at the low end of the range shown, investment costs will be less than the estimated savings from storage up to about 25 MW of storage capacity in the 50 MW wind case. In the 70 MW wind case, best-case storage costs never exceed estimated savings for the set of scenarios analyzed. In the high wind capacity scenarios, the economic value of storage is greatest when storage is sized around 10 MW on São Miguel, however that value disappears if storage costs more than $2,500/kW, or 1,800€/kW.

Table 7.4 shows how the optimal size of storage installations change depending on the cost of storage and the amount of wind capacity. At the low end of the storage cost range, no bulk storage should be installed on the current system, however that grows to as high as 12.5 MW of storage on a 70 MW wind system. If storage costs are at the high end of the range, on the other hand, no storage should be installed until 70 MW wind penetration is achieved. Even then, a small storage system is appropriate to capture relatively little value from storage; larger storage systems would be over-investment and lead to economic losses.

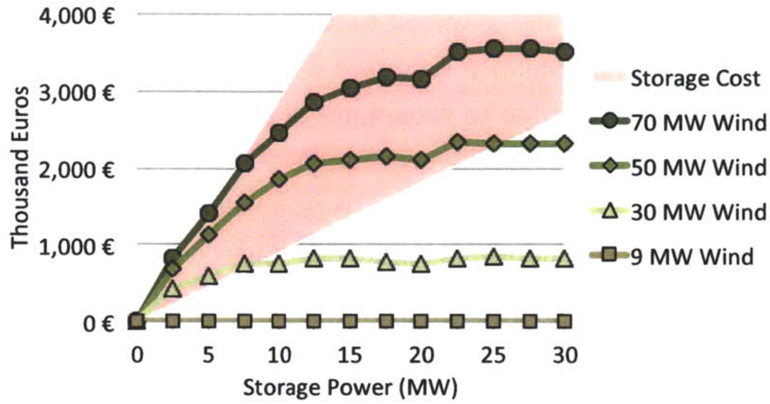


Figure 7-18: Savings versus investment cost of storage on São Miguel

	Capital Cost of Storage	
Installed Wind Capacity (MW)	Low Cost Storage 940 €/kW	High Cost Storage 3,000 €/kW
9	0.0 MW	0.0 MW
30	2.5 MW	0.0 MW
50	10.0 MW	0.0 MW
70	12.5 MW	2.5 MW

Table 7.4: Storage power to achieve maximum operating cost savings on São Miguel

Faial

Figure 7-19 shows a similar chart for Faial. On Faial for both the 12 and 18 MW wind cases and low-cost storage, the economic value of storage is greatest when storage is sized around 2–3 MW. However, as seen in Figure 7-10 the clean energy target of 75% renewables is not achieved at this wind/storage combination. With 18 MW of wind on Faial and low-cost storage, the estimated cost savings are greater than annualized storage investment costs even at 6 MW of storage power, however this wind-storage configuration still only achieves about 73% clean energy. At higher costs of storage, the case for storage investment quickly dissipates. As seen in Table 7.5, high-cost storage only makes sense at the highest wind penetration modeled. Similar to São Miguel, at high wind penetrations, storage should cost no more than 1,800€/kW in order to be economically viable.

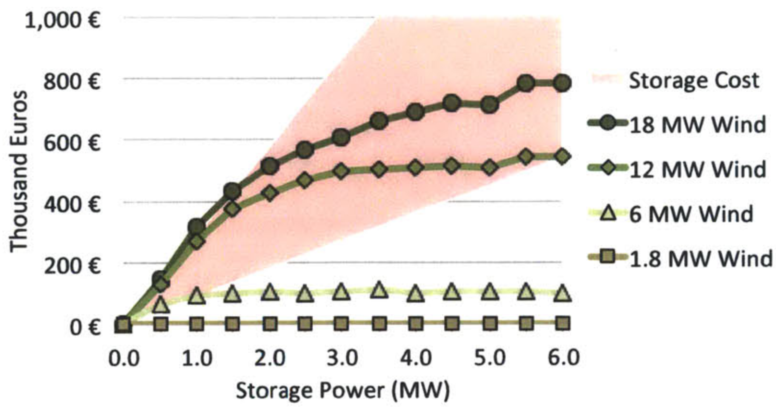


Figure 7-19: Savings versus investment cost of storage on Faial

	Capital Cost of Storage	
Installed Wind Capacity (MW)	Low Cost Storage 940 €/kW	High Cost Storage 3,000 €/kW
1.8	0.0 MW	0.0 MW
6.0	0.5 MW	0.0 MW
12.0	2.0 MW	0.0 MW
18.0	3.5 MW	1.0 MW

Table 7.5: Storage power to achieve maximum operating cost savings on Faial

Flores

Figure 7-20 compares the estimated savings and costs from storage on Flores. In this case, bulk storage is only economic at the high wind penetrations of 2–3 MW, or possibly at 1 MW of wind for a very low-cost and small storage installation. Storage offers the highest value around 250–350 kW of storage, however storage does not make economic sense at any size if it costs more than about 1,750€. Table 7.6 shows how the optimal storage size changes over different storage costs and wind penetrations. Storage only makes sense on Flores if it is fairly low cost, and even then it is only viable at higher wind penetrations than currently installed on the island.

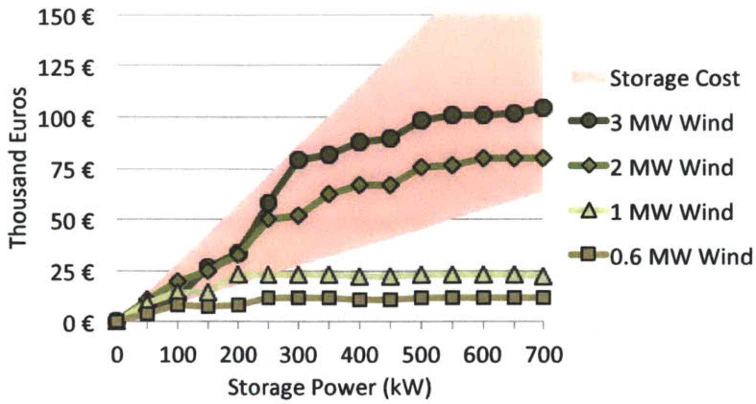


Figure 7-20: Savings versus investment cost of storage on Flores

	Capital Cost of Storage	
Installed Wind Capacity (MW)	Low Cost Storage 940 €/kW	High Cost Storage 3,000 €/kW
0.6	0 kW	0 kW
1.0	100 kW	0 kW
2.0	350 kW	0 kW
3.0	500 kW	0 kW

Table 7.6: Storage power to achieve maximum operating cost savings on Flores

Due to the irregular shape of the cost savings curves on Flores, these finding appear to be highly sensitive to power system characteristics—where 250 kW of low-cost storage offers clear economic value on the 2–3 MW wind system, 200 kW of storage on the same system provides significantly less value. At higher investment cost levels, the large difference in savings between 200 kW and 250 kW storage installations could make the difference between a project that is uneconomic versus one that is economic. This suggests that further analysis should be undertaken to understand the nature of Flores electricity supply and demand, as well as careful cost and performance modeling for selected storage technologies, before making investments in storage projects.

7.7 Sensitivity analysis

All input assumptions in this analysis are subject to uncertainty, which can lead to different operating decisions and costs. Each input parameter will affect generation and cost results in a different way, depending on which factors the parameter influences most directly. A limited number of sensitivity analyses were performed in order to explore the potential effects of alternative future scenarios for key parameters.

Fuel costs

The most important determinant of electricity costs on islands is the cost of fuel. As fuel oil and diesel costs rise and fall, that price is directly passed through to the total cost of generation. On islands with limited diversity of generation types, and where fuel oil is already the most expensive generation option, islands do not have the option of switching to other generation sources when oil prices increase. Depending on expectations for future fuel costs, the economic case fore renewable energy and storage will be be stronger at higher fuel costs. With respect to other factors, whereas costs can change significantly, total generation from fuel oil and diesel (as well as unit start and dispatch decisions) do not change measurably from changes in fuel costs.

São Miguel was modeled for a scenario of 25 €/MMBtu, compared to the baseline assumption of 15 €/MMBtu. For the existing generation mix on São Miguel, including 9 MW of wind capacity and holding all other assumptions fixed, total annual operating costs are estimated to be 19 million euro higher than the case with 15€ fuel—nearly a 40% increase in operation costs. The cost impact from higher fuel costs is slightly less if energy storage is installed, however the observed effect is limited because storage utilization is low in the low wind scenarios. These results are summarized in Table 7.7.

Storage Power (MW)	15 Euro Fuel Annual Cost (thousand €)	25 Euro Fuel Annual Cost (thousand €)
0	50,163	69,341
10	50,159	69,191

Table 7.7: Impacts from higher fuel costs; São Miguel with 9 MW wind

In a scenario of 70 MW of wind installed on São Miguel and no energy storage, estimated total annual operating costs are nearly 13 million euro higher in the case of 25€ fuel compared to 15€ fuel. The cost increase is less than the 9 MW wind case due to lower total generation from fuel oil when more wind is installed. With 10 MW of storage, annual costs are about 9 million euro higher than the 15€ fuel case. In the high fuel cost case, energy storage saves approximately 6 million euro per year. These results are summarized in Table 7.8. Whatever the level of installed wind capacity, the relative levels of generation from fuel oil and renewable resources remain the same between the two fuel price scenarios.

Storage Power (MW)	15 Euro Fuel Annual Cost (thousand €)	25 Euro Fuel Annual Cost (thousand €)
0	46,431	59,155
10	43,981	52,803

Table 7.8: Impacts from higher fuel costs; São Miguel with 70 MW wind

The impact from changes in fuel costs is expected to be similar on other islands: higher fuel costs will result in a direct pass-through to higher electricity costs. On islands that rely almost exclusively on oil for electricity, such as Faial, the relative effect of a percentage-increase in fuel costs on the percentage-increase in total operation costs will be closer to 1-for-1 than as seen on São Miguel, because São Miguel benefits from a large share of geothermal and other renewable capacity.

Demand growth

This analysis has assumed that electricity demand on each island will grow by 8% from 2010 to 2018, a fair assumption given economic growth potential and increases in tourism to the Azores. Different demand patterns will result in very different generation capacity and operating needs, however. For example, lower demand growth—available through energy efficiency programs, for instance—can lead to less capacity needs and lower fuel costs. These effects were tested on São Miguel, for a case where demand is held constant at 2010 levels and all other assumptions held fixed (including 15€ fuel). On the existing network with 9 MW of wind, lower demand levels would save about 4.5 million euro in annual costs, compared to the higher demand case. In addition, the lower total demand means that less fuel is burned for electricity and thus a higher share of generation is provided by renewable resources. These results are summarized in Table 7.9.

	8% Demand Growth		Zero Demand Growth	
Storage Power (MW)	Annual Cost (thousand €)	Renewable Energy (%)	Annual Cost (thousand €)	Renewable Energy (%)
0	50,163	51%	45,635	55%
10	50,159	51%	45,629	56%

Table 7.9: Impacts from lower demand; São Miguel with 9 MW wind

Lower demand offers the potential to achieve the Azores 75% clean energy goal with less investment in renewable generation capacity. Table 7.10 shows this effect for

São Miguel with 50 MW of wind. Whereas total renewable generation will account for around 66% of generation if demand grows by 8%, it can provide 70% of energy at 2010 demand levels. With 10 MW of energy storage, this is enough to tip annual renewable generation above the 75% level. Whereas 70 MW of wind plus storage was previously needed to achieve the 75% goal, the combination of flat demand growth, 50 MW of wind and 10 MW of storage also achieves the goal, while also reducing total operating costs.

	8% Demand Growth		Zero Demand Growth	
Storage Power (MW)	Annual Cost (thousand €)	Renewable Energy (%)	Annual Cost (thousand €)	Renewable Energy (%)
0	46,717	66%	42,888	70%
10	44,875	74%	40,805	78%

Table 7.10: Impacts from lower demand; São Miguel with 50 MW wind

Geothermal expansion on São Miguel

As discussed in Section 5.5.3, EDA plans to increase geothermal capacity on São Miguel. This project will significantly increase the amount of baseload generation on the island, resulting in reduced dependence on fuel oil and increased renewable generation. Although the exact parameters of the proposed project are unknown, 10 MW of additional geothermal was modeled on São Miguel to investigate the possible effects.

If 10 MW of geothermal capacity is added to the existing São Miguel network (keeping all other parameters fixed, including 15€ fuel costs and 8% growth to 2018), annual operating cost savings of around 3 million euro are expected. More significantly, total renewable energy will increase from around 50% to 70%—approaching the 75% goal without any additional wind. These results are summarized in Table 7.11.

	Existing Geothermal Capacity		Expanded Geothermal Capacity	
Storage Power (MW)	Annual Cost (thousand €)	Renewable Energy (%)	Annual Cost (thousand €)	Renewable Energy (%)
0	50,163	51%	47,053	69%
10	50,159	51%	46,582	69%

Table 7.11: Impacts from geothermal expansion; São Miguel with 9 MW wind

Table 7.12 shows the same information for a case of São Miguel with 30 MW of installed wind. Notably, the addition of 10 MW geothermal capacity enables São

Miguel to achieve the 75% clean energy benchmark with much less wind capacity than is possible on the current system. More than 75% renewable energy is achieved even without energy storage if 30 MW of wind is installed, however the total share of renewables increases further with energy storage.

	Existing Geothermal Capacity		Expanded Geothermal Capacity	
Storage Power (MW)	Annual Cost (thousand €)	Renewable Energy (%)	Annual Cost (thousand €)	Renewable Energy (%)
0	47,629	63%	45,210	77%
10	46,886	65%	43,670	81%

Table 7.12: Impacts from geothermal expansion; São Miguel with 30 MW wind

While geothermal expansion will provide signficantly more renewable energy and some cost savings, it will also introduce operational challenges on São Miguel. 10 MW of additional geothermal will put total baseload generation capacity on the island at or greater than off-peak demand levels for many days in the year, meaning that these units will not be able to be operated at full output in all hours. Although geothermal output should in theory be able to be curtailed in some hours, EDA does not operate the units in this way at present, instead running them at fairly constant output thought the day and year. Figure 7-21 shows this expected impact for one week on São Miguel, with 30 MW installed wind capacity and high wind availability. In order to keep all three geothermal units on in all hours, and to maximize clean energy generation while maintaining reserve requirements, geothermal output must be ramped down in all overnight hours as well as some daytime hours. Furthermore, significant wind curtailment is necessary.

Energy storage provides a solution to this problem, allowing excess generation to be stored overnight then discharged during the day. Figure 7-22 show this effect. Even with energy storage, however, some wind and geothermal curtailment still occurs—likely for the purposes of maintaining reserve requirements and to avoid turning off ICE units for very short periods. In practice, energy storage might be able to be used to completely eliminate geothermal curtailment.

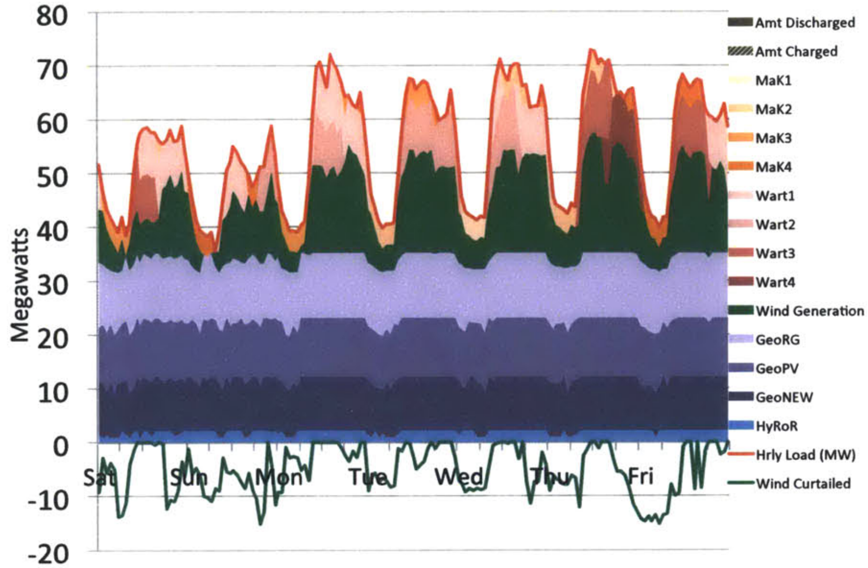


Figure 7-21: São Miguel generation dispatch with geothermal expansion

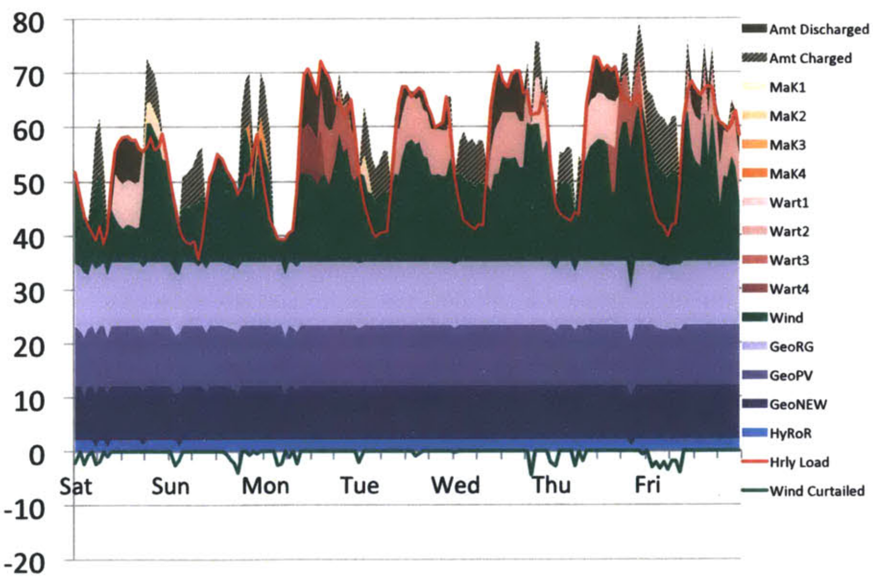


Figure 7-22: São Miguel generation dispatch with geothermal expansion and storage

Chapter 8

Conclusions

8.1 Summary of key findings

Installation of energy storage on island power systems can lead to large operating cost savings and the ability to achieve higher shares of renewable generation. The cost savings are attributable to a combination of storage effects, including fewer start-ups and shut-down of generating units and lower consumption of expensive fuel oil and diesel. The higher share of renewable generation is due to the ability of storage to shift energy from hours in which it is generated to later hours when it is needed, resulting in less curtailment of renewables. In addition, renewable generation increases due to the provision of operating reserves from storage rather than requiring additional thermal units to remain online, thus further reducing renewable curtailment.

Annual cost savings from storage depend on the size of storage, as well as the generation mix of the power system on which storage is installed. The majority of cost reductions are due to reduced expenditures for imported fuel oil and diesel fuel. Operating cost savings are larger as the installed capacity of wind increases due to the lower cost of wind generation (measured at applicable rates for Portuguese feed-in tariffs) compared to fuel costs for oil generation. At the high end of wind penetration and storage sizes modeled, annual operating cost savings might reach 3.5 million euro on São Miguel, 800,000 euro on Faial, and 100,000 euro on Flores. Those estimates do not include capital investment costs for wind and storage installations, which can be expected to reduce total savings and might suggest lower total investments in wind and storage.

Operating reserve requirements are a critical reliability concern on power systems, which energy storage is well-suited to serve. Where current island systems need to maintain thermal generating units online at reduced output levels in order to be available for spinning reserves, storage can provide this reserve and therefore allow some thermal units to be turned off. Those remaining thermal units can be run at higher, more efficient output levels. In many situations, energy storage does not necessarily need to actively charge and discharge but rather can provide an "option value" for reserves simply by remaining available at an appropriate level of charge.

A significant share of estimated cost reductions derive from avoided starts and stops of units. In the absence of energy storage, the islands rely on a limited set of internal combustion engine (ICE) generation units to provide grid services ranging from baseload generation to load-following and peak power. This typically requires the daily start-up of one or more units as demand increases through the day, then subsequent shut-down overnight or on weekends. The addition of variable-output renewable generation will tend to increase the number of starts and stops of ICE units as the swings in net load become larger. Depending on the costs attributable to unit start/stops—typically large due to additional fuel consumption and wear and tear on equipment—unit starts can account for a large share of operational costs on island power systems. Energy storage can reduce these unit starts by charging or discharging for a small number of hours to avoid the need for an additional unit to turn on or off for that period. This benefit from storage is most significant at low to medium penetrations of wind capacity; at very high wind penetrations, storage is more valuable for providing operating reserves—keeping additional ICE units offline instead of operating at minimum generation levels while other ICE units are relied upon to follow net load.

Research results suggest that islands that rely exclusively on wind may not be able to achieve aggressive clean energy goals. Of the three islands analyzed, São Miguel and Flores each have a significant share of existing renewable capacity (hydro and, in the case of São Miguel, geothermal), whereas Faial relies almost entirely on fuel-burning ICE units. Model results indicate that São Miguel and Flores can achieve the 75% renewable energy goal with their existing generation portfolios plus wind and storage—albeit with large installations of wind capacity. Faial, on the other hand, may not be able to reliably achieve 75% renewable energy using wind and storage alone. Plans to add additional geothermal capacity on São Miguel will further improve the operating costs and renewable generation on the island, including a lower requirement for wind development to achieve 75% renewable energy.

An important insight to emerge from this research is that there will be a diminishing return on both cost savings and total renewable generation from adding increasing amounts of energy storage. Incremental cost savings will tend to be largest from relatively small storage installations. As storage size increases, the marginal savings decline until a point at which no additional benefit from storage can be derived (i.e. storage is over-sized for the system). Similarly, total renewable generation increases as storage size increases—especially at high penetrations of wind—however that effect is greatest for small storage installations. The diminishing return on storage suggests that, because the cost savings and renewable energy impacts from storage need to be balanced against the higher investment costs from large storage installations, the optimal size of storage will be less than the maximum operating cost savings found in this research.

Storage power for charging and discharging (measured in MW) is found to be more important than storage capacity (measured in MWh) for achieving cost savings and higher renewable generation. Figure 8-1 illustrates this result for cost savings, taking the case of São Miguel with 70 MW of installed wind as an example. As can be seen, there is a significant savings from storage as the charging and discharging power increases—from less than half a million euro per year to nearly 4 million euro. On the other hand, there is limited improvement in savings from increases in storage capacity; at fixed power levels, the cost savings are quite flat across different capacity levels, with the exception of some diminished savings at the smallest-sized capacities.

Notably, there is a diminishing return to operating cost savings as storage power increases, and indeed the the savings "plateau" around 25 MW storage power, after which storage size exceeds system needs. In light of this effect, Figure 8-1 includes a highlighted oval to suggest the area on the chart where storage might be optimally sized for São Miguel. In this case, energy storage of around 10 MW power and 20 MWh capacity appears to provide the best value before serious diminishing returns set in. 10 MW of storage represents about 12% of forecasted peak load on São Miguel in 2018. Similar results are seen on the smaller islands analyzed, although a higher return on energy capacity is seen on the smallest island of Flores—possibly due to the larger relative variations in load on the smaller network.

The higher value from storage power over capacity is partially attributable to the deterministic nature of the unit commitment model, which preferences storage for the option value of providing reserve requirements rather than actual energy delivery. An analysis of stochastic wind and load shapes might find a higher utilization of storage—beyond the stand-by option value for reserves—which would lead to greater depletion (and subsequent replenishing) of stored energy. In real-world operation, in which generating units are committed and wind curtailment decisions are made in advance, *a priori* of deviations in load and wind from forecasted levels, storage

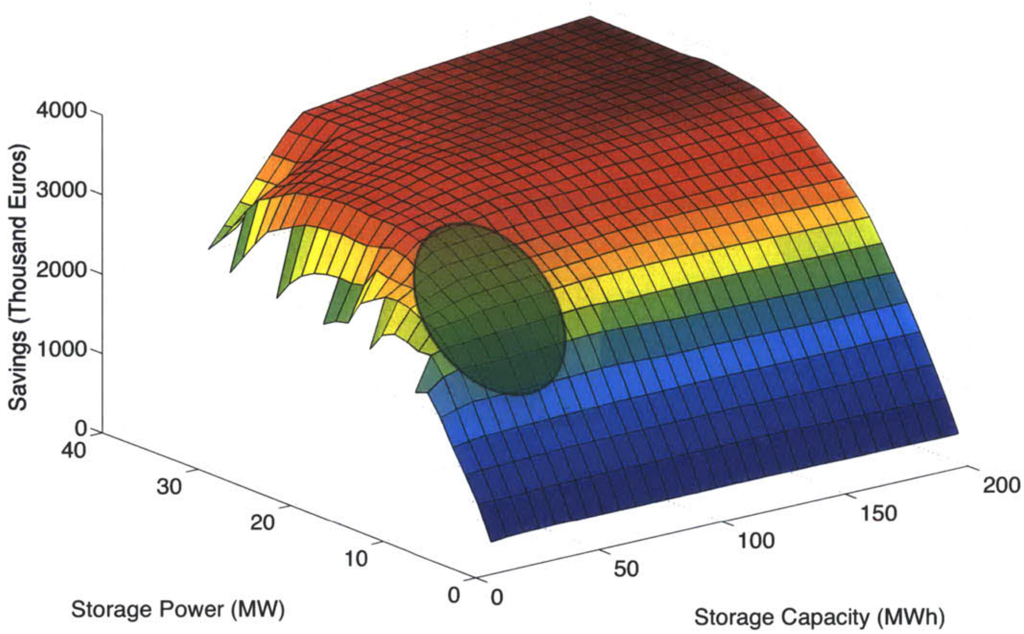


Figure 8-1: Example of operating cost savings and optimal size of energy storage

is expected to be charged and discharged more frequently (i.e. more utilization of storage)—leading to greater need for energy capacity.

Further research is needed to understand the sensitivity of these results to changes in other assumptions such as energy storage performance. Detailed analysis should also be undertaken to understand the use of storage for fast-response services such as frequency regulation and minute-to-minute smoothing of net load. Nonetheless, this analysis supports an emerging research consensus that renewable energy coupled with energy storage can significantly reduce electricity costs and greenhouse gas emissions on islands.

8.2 Discussion

There are a set of familiar environmental policy proposals for addressing climate change, including carbon taxes and cap and trade systems. Those tools may not be appropriate for smaller systems and economies, however, which operate as price takers in the global economy and stand to incur significant cost and lose competitive standing from such "market mechanisms" without necessarily seeing any benefit. In the case of islands, policy will need to address a particular set of barriers that result from carbon lock-in, including technology mismatches from energy system designs tailored to larger networks, financial barriers from high upfront costs of clean energy investment, and knowledge gaps from understaffed island utilities and limited energy planning organizations devoted to islands.

Furthermore, efforts to de-carbonize the electricity system and achieve greater energy security cannot be separated from technical considerations of the system. System planners must maintain resource adequacy and security of supply in order to provide power that meets reliability and power quality standards. This means that—at the local level at which individual island electric networks are planned and operated—policy options must address technical criteria of the finest detail, as well as financial barriers at the firm-level and microeconomic scale, rather than national or global economy.

This research has explored these social and technical features of island power systems in an effort to understand their historical development, as well as the case for transitioning to a cleaner, less carbon-intensive electricity supply. Specifically, wind generation coupled with energy storage is shown to reduce total operating costs on three island power systems in the Azores archipelago. While very large penetrations of wind capacity are needed to achieve benchmark clean energy targets of 75% clean energy—on the order of 1–2 times the peak load of the network—relatively small amounts of storage can have substantial benefit in reducing operating costs and increasing renewable generation. Based on modeling results for the three islands under review, optimal sizing of storage appears to be around a tenth to a quarter of the size of system peak load, although exact ratios will change between islands depending on the generation mix and level of variable-output renewables, among other factors.

Based on these results and similar findings elsewhere, the Azores electric utility, Electricidade dos Açores, should continue to pursue energy storage projects to complement ongoing wind and other renewable energy investments. One such project is under development on the island of Graciosa, which will provide valuable operational experience that can inform future investment decisions. EDA and island electricity planners everywhere should bear in mind, however, that most energy storage designs remain unproven technologies with unknown actual performance details and lifetime costs. Given this, islands should proceed cautiously in undertaking major capital investments until technologies and experience improve. As long as technologies remain unproven and risks high, island utilities should take care to manage investment risks through careful cost modeling and contract terms with technology vendors.

While the development of energy storage and renewable generation capacity offers high-profile and technologically-exciting projects, island energy planners should not overlook other programs and services that can achieve the same goals. First and foremost, energy efficiency measures offer the opportunity to reduce total energy consumption for the same level of economic activity, while providing significant savings in fuel costs and capital investment. Compared to the base case analyzed in this research, in which electricity demand grows 8% between 2010 and 2018, an estimated 4 million euro annual cost savings are estimated for São Miguel if electricity demand remains flat. That level of savings holds across a range of wind penetration and storage sizing scenarios, all else being equal. In addition to operating cost savings, energy efficiency would enable the Azores to achieve the same share of renewable energy generation as a higher load growth scenario, but for less total investment in wind or other renewables capacity. Other energy management programs such as demand response or dynamic pricing schemes would provide similar high value benefits for relatively little cost.

Importantly, the social value of installing emerging technologies such as energy storage on islands is larger than the potential savings for the islands themselves. Island energy systems offer a valuable test bed for new technology designs and concepts, which if proven successful can be "exported" to larger systems and scaled up in order to achieve significant change elsewhere. Likewise, advanced operating procedures for energy management can be developed and refined on island networks, then adapted for mainland grids. In light of this opportunity for positive externalities from island clean energy investment, there is a strong case for other countries and mainland governments to provide financial support and resources for island energy systems. In this manner, long-term economic and climate goals can be pursued while at the same time islands can begin to develop new human capital and knowledge economies where historically islands have been at a deficit.

Appendix A

Sample GAMS code

A sample of the GAMS code for the mixed-integer linear optimization used in this research is provided below. The code shown is for the island of Faial for a scenario of 1.8 MW of installed wind capacity and a high wind week. Code for other islands will have some minor variations, including for the number and types of generators modeled.

Unit commitment model for Faial

This section provides the main code used in this analysis, including the definition of sets, parameters and equations. The code also includes a loop around the solve statement, which is used to solve the model numerous times in succession, over a range of different storage size parameters (in this case 79 different storage sizes, numbered s0 through s78). The specific output commands used in this research are excluded from the code shown. Results can be outputted in many different formats from GAMS; in this research outputs to csv files were used.

Some input parameters are input in separate files, called from this file by the "$include" commands that follow the SETS definitions.

<u>Unit commitment model MIP code</u>

```
OPTION OPTCR = 0.01

SETS
g generators / ICE1, ICE2, ICE3, ICE4, ICE5, ICE6, Hydro, Wind /
g_NonWind(g) Non wind generators / ICE1, ICE2, ICE3, ICE4, ICE5, ICE6, Hydro /
GEN_PARAMS generation parameters /Fcost, VOM, HR, Pmax, Pmin, Startup, Ramp, MinUpDown/
dl demand levels / 1*168 /
```

```
STOR_PARAMS storage configurations / ChrgRate, StorMax /
s storage configurations / s0*s78 /
;

alias(dll,dl);

$include FAI_GenParams_Stor.gms
$include FAI_Load2018_WindHigh.gms


Parameter pWcap(dl)  Forecasted wind power in each period ;
pWcap(dl) = pGenData('Wind','Pmax') * pWcf(dl);


*RESULTS PARAMETERS
Parameter pGenresults(s,g,dl)       Generation output in MW;
Parameter pTotalGen(s,g)            Total generation for each generator over full week (MWh);
Parameter pWindCurtail(s,dl)        Wind curtailment in each period of each scenario (MW);
Parameter pChrgResults(s,dl)        Energy charged in each period in MWh;
Parameter pDChrgResults(s,dl)       Energy discharged in each period in MWh;
Parameter pStorLevelResults(s,dl)  Charge level of storage unit at start of each period in MWh;
Parameter pAvailCap(s,dl)           Capacity available in each period from committed units (MW);
Parameter pUpReserveMarg(s,dl)      Up spinning reserve margin in each period;
Parameter pStartResults(s,g)        Number of total starts by each generator;

Parameter pHourlyPrice (s,dl)      Marginal cost of the last unit scheduled in dl in $ per MW;
Parameter pChrgRateS               Equals pChrgRate in each scenario s;
Parameter pDChrgRateS              Equals pDChrgRate in each scenario s;
Parameter pStorMaxS                Equals pStorMax in each scenario s;
Parameter pStorMinS                Equals pStorMin in each scenario s;
Parameter pStorCapacityResult(s)  Total storage capacity (Max - Min) used in each scenario s;
Parameter pMaxChrgResult(s)        Maximum storage charge power used in each scenario s;
Parameter pMaxDChrgResult(s)       Maximum storage discharge power used in each scenario s;

Parameter pC(g)                   Generation cost in $ per MWh of each plant;
pC(g) =  pGenData(g,'Fcost')*pGenData(g,'HR')/1000 + pGenData(g,'VOM');

Parameter pOpCost(s)    Operating Costs (obj value) resulting from each scenario;



VARIABLES
vW(g,dl)            generation with Ramp limit
x(g,dl)             generation of each plant in each dl in MW
z                   total cost
vStartUpCost        total cost from start-ups
vGenerationCost     total cost from generation
vStorLevel(dl)      amount of energy in storage at start of each period in MWh
vChrgAmt(dl)        amount of energy added to storage during each period in MWh
vDChrgAmt(dl)       amount of energy discharged from storage during each period in MWh
;

POSITIVE VARIABLES
x                    decision variable
vChrgAmt             amount charged
```

```
vDChrgAmt           amount discharged
;

BINARY VARIABLES
vU(g,dl)             unit commitment state for generator g in dl [0 1]
vUp(g,dl)            binary variable to start up [0 1]
vDown(g,dl)          binary variable to shut down [0 1]
vChrg(dl)            binary variable to charge storage unit [0 1]
vDChrg(dl)           binary variable to discharge storage unit [0 1]
;


EQUATIONS
eCost                 objective function
eStartupcost          total start-up costs
eGenerationcost       total generation cost
ePmax(g,dl)           observe supply limit at plant g
ePmin(g,dl)           output greater than Pmin
eDemand(dl)           satisfy total demand

eUpReserves(dl)       Ensure that Spinning Reserve-up requirements are met
eDownReserves(dl)     Ensure that Spinning Reserve-down requirements are met
eNonSpinReserve(dl)  Ensure that one oil unit (of largest size) is always kept off

eState(g,dl)         compute unit commitment states
eRampUp(g,dl)        observe ramp limits of each plant in each hour
eRampDown(g,dl)      observe ramp limits of each plant in each hour
eTotalgen(g,dl)      Generation is equal to Pmin plus vW
eMinUp(g,dl)         Must satisfy min-up time for each plant in each hour
eMinDown(g,dl)       Must satisfy min-down time for each plant in each hour
eStorLevel(dl)       Storage level depends on previous hour and amt charged or discharged
eChrgState(dl)       Cannot charge and discharge in the same period
eChrgRate(dl)        Observe charge rate limit
eDChrgRate(dl)       Observe discharge rate limit
eStorMax(dl)         Storage capacity is observed in every period
eStorMin(dl)         Storage minimum is observed in every period
eWindGen(dl)         Total wind gen in each period (to allow for curtailment)
;

eCost..              z =e= vStartUpCost + vGenerationCost ;
eStartupcost..       vStartUpCost =e= sum((g,dl), vUp(g,dl)*pGenData(g,'Startup'));
eGenerationcost..    vGenerationCost =e= sum((g,dl), pC(g)*x(g,dl));
ePmax(g,dl)..        x(g,dl) =l= vU(g,dl)*pGenData(g,'Pmax') ;
ePmin(g,dl)..        x(g,dl) =g= vU(g,dl)*pGenData(g,'Pmin') ;
eDemand(dl)..        sum(g, x(g,dl)) + vDChrgAmt(dl) =e= pDEM(dl) + vChrgAmt(dl) ;

eUpReserves(dl)..    sum(g_NonWind, vU(g_NonWind,dl)*pGenData(g_NonWind,'pMax')) - sum(g_NonWind, x(g_NonWind,dl))
   + [vDChrg(dl)*pDChrgRateS - vDChrgAmt(dl) + vChrgAmt(dl)] =g= pDResReqt*pDem(dl) + pWResReqt*x('Wind',dl) ;

eDownReserves(dl)..   sum(g_NonWind, x(g_NonWind,dl)) - sum(g_NonWind, vU(g_NonWind,dl)*pGenData(g_NonWind,'pMin'))
   + [vChrg(dl)*pChrgRateS - vChrgAmt(dl) + vDChrgAmt(dl)] =g= pDResReqt*pDem(dl) + pWResReqt*x('Wind',dl) ;

eNonSpinReserve(dl).. vU('ICE1',dl) + vU('ICE2',dl) + vU('ICE3',dl) + vU('ICE4',dl)
                      + vU('ICE5',dl) + vU('ICE6',dl) =l= 5;
```

```
eState(g,dl)..          vU(g,dl) =e= vU(g,dl--1) + vUp(g,dl) - vDown(g,dl);
eRampUp(g,dl)..         vW(g,dl) - vW(g,dl--1) =l= pGenData(g,'Ramp') ;
eRampDown(g,dl)..       vW(g,dl--1) - vW(g,dl) =l= pGenData(g,'Ramp') ;
eTotalgen(g,dl)..       x(g,dl) =e= vW(g,dl) + vU(g,dl)*pGenData(g,'Pmin') ;
*eGenAboveMin(g,dl)..   vW(g,dl) =l= vU(g,dl)*[pGenData(g,'Pmax') - pGenData(g,'Pmin')];

eMinUp(g,dl)..         vU(g,dl) =g= sum((dll)$(ord(dll) > ord(dl) - pGenData(g,'MinUpDown') AND ord(dll)
                        <= ord(dl)), vUp(g,dll)) ;

eMinDown(g,dl)..       1 - vU(g,dl) =g= sum(dll$(ord(dll) > [ord(dl) - pGenData(g,'MinUpDown')] AND [ord(dll)
                        <= ord(dl)]), vDown(g,dll)) ;

eStorLevel(dl)..      vStorLevel(dl) =e= vStorLevel(dl--1) + (pStorEff * vChrgAmt(dl--1)) - vDChrgAmt(dl--1);
eChrgState(dl)..      vChrg(dl) + vDChrg(dl) =l= 1;
eChrgRate(dl)..       vChrgAmt(dl) =l= vChrg(dl) * pChrgRateS;
eDChrgRate(dl)..      vDChrgAmt(dl) =l= vDChrg(dl) * pDChrgRateS;
eStorMax(dl)..        vStorLevel(dl) =l= pStorMaxS;
eStorMin(dl)..        vStorLevel(dl) =g= pStorMinS;

eWindGen(dl)..       x('Wind',dl) =l= pGenData('Wind','Pmax') * pWcf(dl);


model Azores_UC includes all equations /all/ ;

loop (s,
              pChrgRateS = pStorData(s,'ChrgRate');
              pDChrgRateS = pDChrgRate(s);
              pStorMaxS = pStorData(s,'StorMax');
              pStorMinS = pStorMin(s);

   solve Azores_UC using mip minimizing z ;

*CALCULATION OF OUTPUT RESULTS
              pOpCost(s)=z.l;
              pStartResults(s,g) = SUM(dl, vUp.l(g,dl));
              pHourlyPrice(s,dl) = eDemand.m(dl);
              pChrgResults(s,dl) = vChrgAmt.l(dl);
              pDChrgResults(s,dl) = vDChrgAmt.l(dl);
              pStorLevelResults(s,dl) = vStorLevel.l(dl);
              pStorCapacityResult(s) = smax(dl, vStorLevel.l(dl)) - smin(dl,vStorLevel.l(dl));
              pMaxChrgResult(s) = smax(dl,vChrgAmt.l(dl));
              pMaxDChrgResult(s) = smax(dl,vDChrgAmt.l(dl));
              pAvailCap(s,dl) = sum(g_NonWind, vU.l(g_NonWind,dl)*pGenData(g_NonWind,'pMax')) + pDChrgRate(s);
              pUpReserveMarg(s,dl) = (pAvailCap(s,dl) + x.l('Wind',dl) - pDem(dl) - vDChrgAmt.l(dl)) / pDem(dl);
              pGenresults(s,g,dl) = x.l(g,dl);
              pWindCurtail(s,dl) = pGenresults(s,'Wind',dl) - pWcap(dl);
              pTotalGen(s,g) = sum(dl, x.l(g,dl));
      );
```

Input parameters for generator and storage performance

This section provides input tables and other key assumptions for generator and storage size used in the model. In addition, reserve requirements are defined. Some code is omitted to save on space (e.g. storage sizes s4—s73).

Code for input tables and reserve requirements (file *FAI_GenParams_Stor.gms*)

```
table pGenData(g, GEN_PARAMS) Generation data table
        Fcost       VOM     HR          Pmax    Pmin    Startup       Ramp     MinUpDown
*       [E/MMBtu]   [E/MWh] [BTU/kWh]   [MW]    [MW]    [E/start-up]  [MW/hr]  [Hrs]
ICE1    15.0        5       8100        2.5     1.0     150           120      1
ICE2    15.0        5       8100        2.5     1.0     150           120      1
ICE3    15.0        5       8100        2.5     1.0     150           120      1
ICE4    15.0        5       8100        2.5     1.0     150           120      1
ICE5    15.0        5       8100        2.5     1.0     150           120      1
ICE6    15.0        5       8100        2.5     1.0     150           120      1
Hydro   0           0                   0.1     0       10000         0.1      6
Wind    0           0                   1.8     0       0             9.0      1
;


*RESERVE REQUIREMENTS
* Reserve requirements also includes req't that 1 fuel unit remains off-line for non-spinning
* reserve (included in Equations)

Parameter pDResReqt  Required capacity to be committed in each period above forecasted demand;
pDResReqt = 0.05;

Parameter pWResReqt Required capacity to be committed in each period above forecasted wind;
pWResReqt = 0.2;


*STORAGE PARAMETERS

table pStorData(s, STOR_PARAMS) Generation data table
        ChrgRate  StorMax
*       [MW]      [MWh]
s0      0         0
s1      0.5       0.5
s2      0.5       1
s3      0.5       1.5
.
.
.
s74     6.0       10
s75     6.0       20
s76     6.0       40
s77     6.0       60
s78     6.0       80
```

```
;

Parameter pStorEff Efficiency of storage cycle (round-trip);
pStorEff = 0.75;

Parameter pDChrgRate(s) Limit on how fast storage can discharge (MWh per hr);
pDChrgRate(s) = pStorData(s,'ChrgRate');
* Set equal to pChrgRate as approximation.

Parameter pStorMin(s) Min capacity of storage unit (MWh);
pStorMin(s) = pStorData(s,'ChrgRate');
* Minimum storage set equal to max discharge rate in order to ensure one hour of energy is
* reserved and to simplify reserve margin calculations (eliminates possibility that vStorLevel(dl)
* could be lower than pDChrgRate). This equalization approximately maintains storage
* minimum of 10% of maximum in order to prevent deep discharge.
```

Hourly load and wind shapes

This section provides hourly assumptions for demand levels and wind capacity factor. For both parameters, 168 hours are modeled representing 168 hours in the week. Some code is omitted to save on space (e.g. hours 4—167).

Code for load and wind inputs (file *FAI_Load2018_WindHigh.gms*)

```
Parameter
pDEM(dl) Hourly demand levels (MW)
/
1 6.885
2 6.158
3 5.767
.
.
.
168 7.116
/;


Parameter
pWcf(dl) Forecasted hourly wind capacity factor
/
1 0.630
2 0.422
3 0.425
.
.
.
168 0.362
/;
```

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