# SAINT LUCIA NATIONAL ENERGY TRANSITION STRATEGY

# FOREWORD

## FOREWORD FROM THE HONOURABLE STEPHENSON KING, MINISTER FOR INFRASTRUCTURE, PORTS, ENERGY AND LABOUR, GOVERNMENT OF SAINT LUCIA

The Government of Saint Lucia believes a well-functioning electricity system underpins a strong national economy, and is committed to ensuring that all citizens have safe, reliable, and cost-effective access to electricity.

For decades, Saint Lucians have benefitted from a reliable power supply, but at a cost. Our reliance on imported fossil fuels for the generation of electricity has left our small island nation vulnerable to external shocks, due to fluctuations in global oil prices over which we have no control. While in recent years we have benefitted from low oil prices, this trend is unlikely to continue. Not more than three years ago, Saint Lucians were paying over $1 per unit of electricity, more than 50 percent higher than consumers are paying today. Such high costs place an undue burden on residents and businesses, impacting all aspects of the national economy.

Fortunately, Saint Lucia is blessed with natural resources, including an abundance of sunshine, wind, and geothermal energy, that can diversify the generation mix and increase our energy independence. Only a few years ago, these technologies were too costly and immature, but new market forces are evolving across the Caribbean region. Extensive deployment of renewable energy has proven these technologies reliable and have driven costs downward, thus providing opportunities for Saint Lucia to benefit when planning for and implementing the electricity system of the future.

The Government of Saint Lucia acknowledges that the electricity grid is a complex system built upon decades of careful investment that equitably serves all customers. To make the right decisions regarding its future, we recognize the need to understand not only the fundamentals of this system, but also the implications of any future plans on the economics for all electricity consumers. For over 50 years, LUCELEC has provided a reliable and efficient electricity service for Saint Lucia. The Government of Saint Lucia recognizes that a successful evolution of the electricity sector could not happen without the collaboration and expertise of LUCELEC.

Last year, this culminated in the joint development of the National Energy Transition Strategy (NETS) by LUCELEC and the Government of Saint Lucia. The NETS sets a pathway for the next 20 years, including actionable steps to take in the near- to medium-term, providing Saint Lucia with the opportunity to generate electricity with indigenous sources and stabilize the cost of electricity, while at the same time maintaining or improving the reliability of the grid. More importantly, the NETS was a process that brought together key stakeholders in the electricity sector. The collaborative approach has made Saint Lucia a leader in energy transition in the region, and we believe it has led to the development of a more robust plan for Saint Lucia, which will benefit all of our people.

The NETS was informed by independent technical analysis provided by our international nonprofit partners, Rocky Mountain Institute-Carbon War Room and Clinton Climate Initiative (an initiative of the Clinton Foundation).

The Government of Saint Lucia strongly supports the NETS process and the results presented in this document. However, we realize this is only the first step. The Government of Saint Lucia is committed to bringing together the right parties to implement this roadmap for an energy future that benefits all Saint Lucians. In this regard, we continue to welcome the participation and feedback from the public.

# FOREWORD

## FOREWORD FROM TREVOR LOUISY, THE MANAGING DIRECTOR OF ST. LUCIA ELECTRICITY SERVICES LIMITED

Since 1964, St. Lucia Electricity Services Limited (LUCELEC) has provided reliable power for Saint Lucia, driving economic development and prosperous employment for our country. Energy and electricity remain crucially important for all aspects of Saint Lucia's economy, and will power the nation's success for the decades to come. LUCELEC is committed to providing reliable and affordable electricity for Saint Lucia for generations to come, managing the grid responsibly and providing many benefits to the country.

The technologies and approaches to providing safe, reliable, and environmentally responsible power have changed over the decades since LUCELEC first began operating. In particular, the price of imported diesel has fluctuated significantly in recent years. Current low prices benefit our country through lower electricity rates, but we cannot continue to rely solely on this to plan for the future. We at LUCELEC will explore all options, including the best currently available technologies to reduce and stabilize costs, while maintaining safety and reliability throughout the system. New resources, such as solar, wind, and geothermal, can all provide benefit if developed in the right manner. This new interconnected energy space requires long-term planning to develop new sources of generation in a cost-effective manner.

Over the last year, the National Energy Transition Strategy process brought together the critical stakeholders, and they worked with the facts of the current electricity system to chart a least-cost path to the future. The results encapsulated in this report reveal the opportunity for a cleaner and lower-cost electricity system that maintains a stable and safe grid, through pursuing select projects over the next 20 years. Developing the interconnected energy space of the future requires the best efforts of all LUCELEC employees and many more within our country.

LUCELEC is committed to exploring new generation sources to better serve our customers and the country. In the process, new high-skill jobs both inside and outside LUCELEC will be developed. We welcome open collaboration with the Government, NURC, and independent parties such as RMI-CWR. By working with local experts and soliciting public input, LUCELEC will continue to listen to and do our best to meet the needs and priorities of all Saint Lucians.

We commend all partners on their commitment to this open process and are proud to support this effort. We welcome participation from all Saint Lucians in this important effort as we forge ahead with ensuring a sustainable energy future for Saint Lucia.

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RMI, CCI, and Saint Lucian partners thank the Dutch Postcode Lottery, the Global Environmental Facility in collaboration with the United Nations Development Programme, and the Norwegian Agency for Development Cooperation for the funding to support this process.


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# ABOUT US

## ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. In 2014, RMI merged with Carbon War Room (CWR), whose business-led market interventions advance a low-carbon economy. The combined organization has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

## ABOUT THE CLINTON FOUNDATION

The Clinton Foundation convenes businesses, governments, NGOs, and individuals to improve global health and wellness, increase opportunity for girls and women, reduce childhood obesity, create economic opportunity and growth, and help communities address the effects of climate change. The Clinton Climate Initiative (CCI) collaborates with governments and partner organizations to increase the resilience of communities facing climate change while reducing greenhouse gas emissions. CCI has helped generate over 63,000 MWh of clean energy annually in the Caribbean and East African Islands.

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# EXECUTIVE SUMMARY

*"The strong leadership and objective analysis from the Islands Energy Program ensured that a clear vision for the future was established, along with the ability for Saint Lucia to embark on a sustainable path for lower electricity costs and increased energy independence."*

—Sylvester Clauzel, Former Permanent Secretary, Ministry of Sustainable Development, Energy, Science, and Technology, Government of Saint Lucia (2012–2016)

# EXECUTIVE SUMMARY

Saint Lucia's electricity sector faces both opportunities and challenges during a time of emerging new technologies and evolving utility business models. Saint Lucia and St. Lucia Electricity Services (LUCELEC)—the national electric utility—are currently grappling with how to incorporate renewables into the energy sector, which has raised questions regarding the technical operations of the grid, ownership of generating assets, economic viability for all ratepayers, and continued utility financial stability. At the same time, recent developments in energy efficiency, renewable energy, cleaner-burning fuels (e.g., natural gas), electricity storage, and advanced controls and metering present a myriad of opportunities.

Saint Lucia's current electricity system is well managed, reliable, and supports an equitable system. This can be primarily attributed to the fact that LUCELEC is a responsible and financially sound utility. Currently, all generation assets (10 diesel generators) are located at Cul de Sac power station (see Appendix D for more information) and are operated manually to meet loads and required reserves at all times. The ensuing reliance on imported diesel fuel creates relatively high and volatile costs to produce electricity, and leaves the country exposed to a single fuel source. With the increased global investment in renewable energy, changing times in the global energy sector now require a new approach to Saint Lucia's electricity sector.

In 2014, the Government of Saint Lucia announced refined energy targets, setting a renewable energy penetration target of 35 per cent and an energy efficiency target of 20 per cent reduction in consumption in the public sector, both to be achieved by 2020. In 2015, Saint Lucia submitted a climate action plan to the United Nations Framework Convention on Climate Change (UNFCCC) and in April 2016, ratified the Paris Agreement on Climate Change. To reach energy and climate goals while ensuring cost-effectiveness, a deliberately planned energy transition process is critical for all Saint Lucian stakeholders.

As Saint Lucia aims to reduce electricity costs and ensure energy independence through increased adoption of renewable energy and energy efficiency, a number of questions have emerged:

- How much can new technologies such as solar photovoltaics or geothermal energy generation stabilise and reduce costs, while advancing Saint Lucia's goals to reduce greenhouse gas emissions?
- Do certain levels of new technologies threaten grid stability, and if so, how can these constraints be overcome?
- Will regulatory reform help ensure low cost electricity and an equitable system for all Saint Lucians?

- How can participation from the private sector support national objectives?

To answer these questions, the Government of Saint Lucia and LUCELEC engaged Rocky Mountain Institute-Carbon War Room (RMI-CWR) and Clinton Climate Initiative (CCI)—with technical support from DNV GL—to complete this study, leveraging deep and broad expertise in energy systems through an independent and impartial approach.

## THE ENERGY TRANSITION PROCESS

Any transition to pursue energy efficiency and renewable energy requires a thoughtful and participatory process, involving all key stakeholders to align around clear and unifying goals. This is particularly true for island nations given the fact that there is significant competition for land use due to their constrained geographical size. Developing a pathway toward future improvements to the electricity system requires the creation of a fact base focused on the current state, which can then be used to examine future opportunities. Forward-thinking leadership from the Government of Saint Lucia and LUCELEC progressively established the necessary conditions for effective planning and built an open dialogue between all parties. Ultimately, the process led to the codevelopment of a strategy made by and for the Government of Saint Lucia, LUCELEC, and the people of Saint Lucia.

The Government of Saint Lucia and LUCELEC initiated the National Energy Transition Strategy (NETS) process to create a forward-looking strategy for the energy sector. This document specifies the results of the analysis and strategy by defining the techno-economic opportunities, pathways, and implications of the energy transition, established through the creation of an integrated resource plan (IRP). RMI-CWR and CCI—supported by the independent consulting engineers at DNV GL—were commissioned by the Government of Saint Lucia and LUCELEC to support the NETS and the IRP. Funding was provided by the Global Environment Facility through the United Nations Development Program as well as the Dutch Postal Code Lottery and Norwegian Agency for Development Cooperation. RMI-CWR and CCI managed the process in an objective manner, independent of any single party and agnostic to any technology.

The strategy development process involved data collection, analysis, synthesis, review, and periodic public participation. The strategy informs LUCELEC, the Saint Lucia Government, public participants, and the National Utilities Regulatory Commission (NURC), which can learn from this process to inform future regulation for the electricity sector. The process compared many technologies and proposed projects, and examined how different combinations of future investments would work together in the system from a technical, financial, and economic perspective. The ultimate analysis and results were shaped by three main priorities: grid reliability, cost containment, and energy independence (including environmental protection and emissions reductions). This document outlines the techno-economic strategy developed through an IRP process.

### RESULTS

Saint Lucia's energy transition opportunity provides a win-win situation where the Government of Saint Lucia supports constituents through cheaper electricity, and LUCELEC can continue to profit and provide reliable service.

The analytical team supporting the IRP initially examined 14 scenarios for the future energy mix of Saint Lucia, spanning different mixes and ownership approaches for new energy generation. Upon detailed investigation, five viable focus scenarios emerged (as shown in Table 1), each forecasting net benefits when compared against the existing diesel-based generation business-as-usual case, although all scenarios included the continued operation of diesel generation to ensure system stability and cost reduction.

**TABLE 1**
DESCRIPTION OF SELECTED FOCUS SCENARIOS

| SCENARIO | TOTAL COST TO OPERATE (Millions of Eastern Caribbean Dollars over 20 years) | 2025 RENEWABLE PENETRATION (by energy) | DESCRIPTION OF GENERATION ASSETS (in 2025) |
|---|---|---|---|
| 1. Diesel Fuel Only (Reference Case) | $6,173 | 0% | Continued diesel, new diesel installed in 2023 (12.4 MW) |
| 2. Natural Gas | $5,821 | 0% | Natural gas (40 MW) from retrofits and diesel (46.3 MW with new 12.4 MW in 2023) |
| 3. Solar, Decentralized—Debt Constrained | $5,497 | 18.6% | Solar (47 MW, 60% owned by LUCELEC), storage (16 MWh), and continued diesel |
| 4. Solar—Hybrid Ownership | $5,514 | 33.1% | Solar (54 MW, 80% owned by LUCELEC), storage (18 MWh), and diesel |
| 5. Solar, Wind—Centralized, Recommended | $5,533 | 38.9% | Solar (54 MW), wind (18 MW), storage (27 MWh), and diesel—optimal rate reduction |
| 6. Solar, Geothermal, Wind—Centralized | $5,595 | 75.3% | Solar (23 MW), wind (12 MW), geothermal (30 MW), storage (19 MWh), and diesel |

The IRP finds that a portfolio of utility owned diesel, solar, and wind (with storage) offers the best economics (low cost to operate the system, lowest rates at the end of the studied timeframe, relatively low debt, and a strong hedge against volatility in diesel fuel prices) while providing continued reliability.

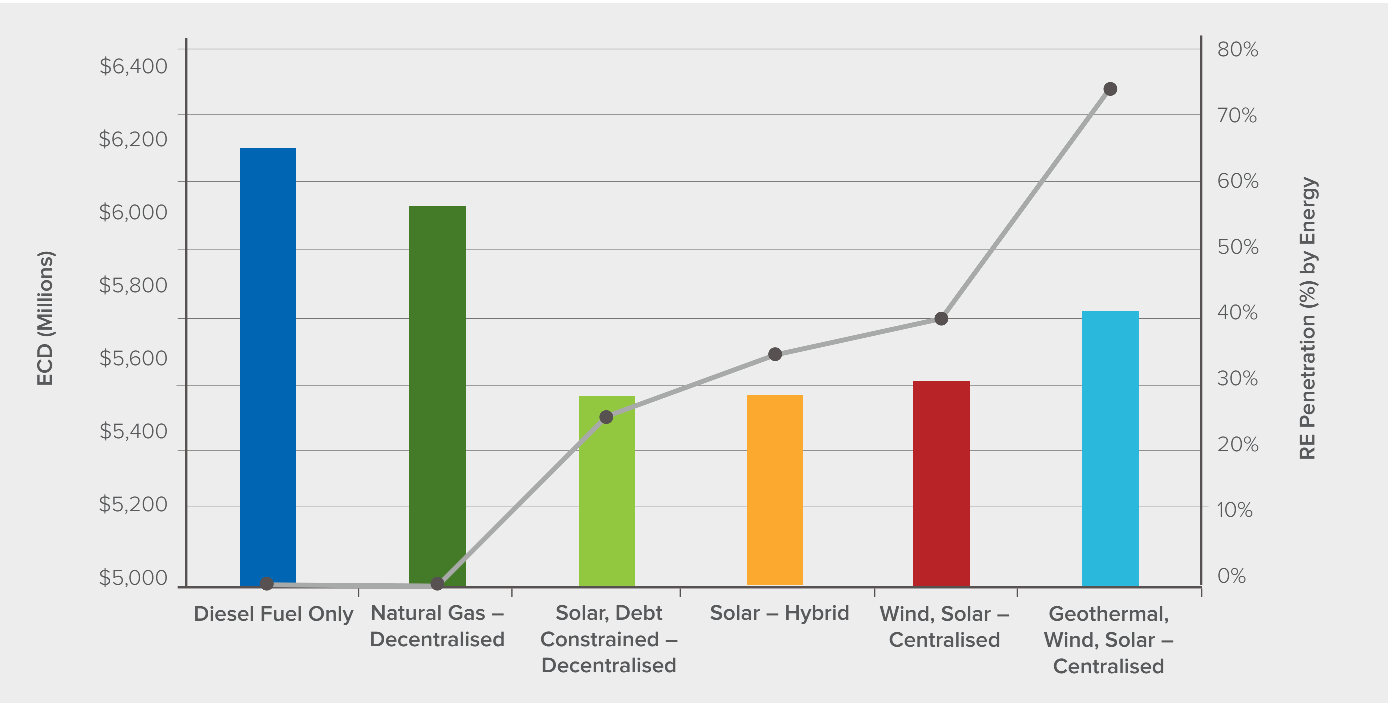
All scenarios presented above meet financial constraints for LUCELEC (including debt tolerance) and maintain or improve grid reliability under all tested load conditions when supported by the inclusion of battery energy storage (between 12 MWh and 27 MWh) systems. Projections for increased electricity usage show that current generation will be sufficient until 2023; however, selectively installing renewable generation in the near term will provide economic benefit for the country.

Results of the IRP are summarised below:

- Pursuing the recommended scenario of centrally owned diesel, solar, wind, and storage outlined above (and in more detail in Appendix F) can provide up to 10 per cent rate relief (within 20 years), stabilise electricity price volatility driven by oil markets by approximately 20 to 25 per cent, and secure a financially strong position for LUCELEC for the coming decades.
- The 20-year incremental capital costs of this plan are approximately Eastern Caribbean (EC) $630 million, and overall societal value is EC$210 million net present value, making it a strong investment for Saint Lucia and LUCELEC.

**FIGURE 1**

TOTAL COST TO OPERATE AND RENEWABLE PENETRATION BY SCENARIO




- The most cost-effective measures are solar and energy efficiency. Solar in the range of 20 MW total in the coming eight years leads to a system levelised cost of electricity (LCOE) reduction of approximately 7 per cent. Energy efficiency, specifically lighting, refrigeration, air-conditioning, and water heating, could save 0.5 per cent per year, growing to 11 per cent of annual sales by 2024, at a levelised cost of EC$0.09 per kWh saved. LUCELEC will require compensation from the NURC to pursue energy efficiency, as current rate regimes do not provide incentives (customer energy efficiency causes lost revenue for LUCELEC). Examples of these types of rate mechanisms include rate-basing the costs of the program (as in Texas) or creating performance-based compensation (as in New York).

- Wind energy, when developed by LUCELEC, offers cost benefits, lowering system-LCOE by approximately 1 per cent, and saving approximately EC$55 million in the in the first 20 years of operating the system.

- Continued development of geothermal should be pursued if the resource in Soufrière can be secured at low cost (power purchase agreement [PPA] below EC$0.38 per kWh). Solar and wind can pair well operationally and financially with geothermal, without creating stranded assets.

After total solar capacity reaches 20 MW (including both utility-owned and distributed solar), new renewable investments require firming through additional energy storage via batteries.

By implementing the optimal scenario, Saint Lucia can exceed national targets for reducing carbon emissions. In the Intended Nationally Determined Contribution (INDC) under the United Framework Convention on Climate Change, Saint Lucia set goals of reaching

16 per cent reduction in carbon emissions versus business as usual by 2025, and 23 per cent reduction versus business as usual by 2030. Pursuing these investments reaches the 35 per cent renewable energy penetration goal (expressed by energy) by 2022. The strategy identified in the NETS process, relying heavily on renewable energy and energy efficiency, moves the electricity generation to surpass those targets, instead reaching a 40 per cent reduction in carbon emissions versus business as usual in 2025, and a 46 per cent reduction in carbon emissions by 2030.

- Moving to deeper carbon reduction and higher renewable penetration (above 60 per cent renewable penetration by 2025 if geothermal is implemented) carries net costs when compared to the optimal scenario,[i] as does meeting renewable targets before the 2020 timeframe. These high renewable scenarios (including geothermal) are in the range of 2 to 5 per cent more costly than the economically optimal scenario, but remain 7 to 9 per cent less costly than the diesel-based reference case. Reaching renewable energy penetration above 50 per cent without geothermal is possible, but ensuring cost parity would require that the cost of solar and storage systems decline faster than 8 per cent year-over-year (in average LCOE).

Pursuing renewable energy and energy efficiency investments requires making long-term decisions in the face of an uncertain future. Numerous factors will influence the economic implications of Saint Lucia's energy transition—in particular changing customer rates, project capital costs, and/or profit projections. The results of the NETS scenarios were tested against various factors to assess the impact of varying future conditions. The analysis presented here tested five primary sensitivities—price of diesel fuel, capital and operating costs for renewable energy and energy efficiency, operating reserve margin, load forecast, and energy efficiency program implementation (see page 54 for more). In particular, the global oil market, and thereby the price of imported diesel fuel, will continue to largely determine the electricity price in Saint Lucia until renewable assets are installed (see Appendix C).

## NEXT STEPS

The integrated resource plan recommends continued efforts to develop and install projects (e.g., solar PV), establish programs (e.g., energy efficiency), modify rate structures, and test and monitor certain technologies that offer potential benefits (e.g., energy storage, automated controls). This analysis includes a five-year plan on efficiency programs, renewable energy, and storage implementation, and includes necessary regulatory changes as well as public participation.

The policies required to support this transition must properly value energy efficiency and allow for managed competition (select independent power producers [IPPs] and capped distributed generation) and local participation (governed by the NURC to ensure ratepayers benefit equitably). LUCELEC's future business model options could include: setting up an energy efficiency business unit (as enabled and supported by regulation), selling renewable energy development services to the region, and exploring new local revenue (e.g., electric vehicles and selling electricity to cruise ships).

This document and all associated models and analysis are designed to be "living" documents, updated on a regular basis under the direction of the NURC.[ii] As such, continued feedback and input is solicited from the Government of Saint Lucia, LUCELEC (and the LUCELEC Board of Directors), and the NURC.

[i] For more information on renewable penetration, see Appendix R.
[ii] Performing the IRP analysis every two to three years is standard for regulated electric utilities.

# 01 CONTEXT

# CONTEXT

In the past 50 years, Saint Lucia gained broad-scale electrification—with over 98 per cent of the population now having access to the electricity grid. The majority of demand growth occurred in the '70s and '80s. Today, Saint Lucia's 67,000 customers annually consume approximately 340 million kilowatt hours (kWh) of electricity with an approximate sales breakdown as follows:

- residential customers ~30 per cent
- commercial including hotels ~60 per cent
- industrial and street lighting ~10 per cent

To generate this electricity, LUCELEC operates 10 diesel generators at the Cul de Sac power station, providing a combined capacity of 86.2 MW (see Appendix D for more information).[1]

**AN EVOLVING ELECTRICITY SECTOR:**

1964—LUCELEC forms, with an exclusive license to provide electricity.

1970s and 1980s—Demand increases as tourism and agriculture boom, causing severe pressure to grow the system. Increased specialisation and self-sufficiency at LUCELEC.

1990s—Opening of Cul de Sac station and establishment of 66 kV transmission system. LUCELEC goes public in 1994.

2000s—Peak demand growth slows due to regional economic difficulties. LUCELEC improves reliability and stabilises customer electricity costs.

2010s—Saint Lucia examines new regulatory models as well as technological change, while ensuring continued strength for LUCELEC.

Power is generated at 11 kilovolts (kV), then stepped up and transmitted at 66 kV from the Cul de Sac power generation station to six substations (Castries, Reduit, Union, Soufrière, Praslin, and Vieux Fort) all located around the exterior of the island (arranged in two rings). These substations serve 32 distribution feeders stepping down to 11 kV (the distribution voltage).

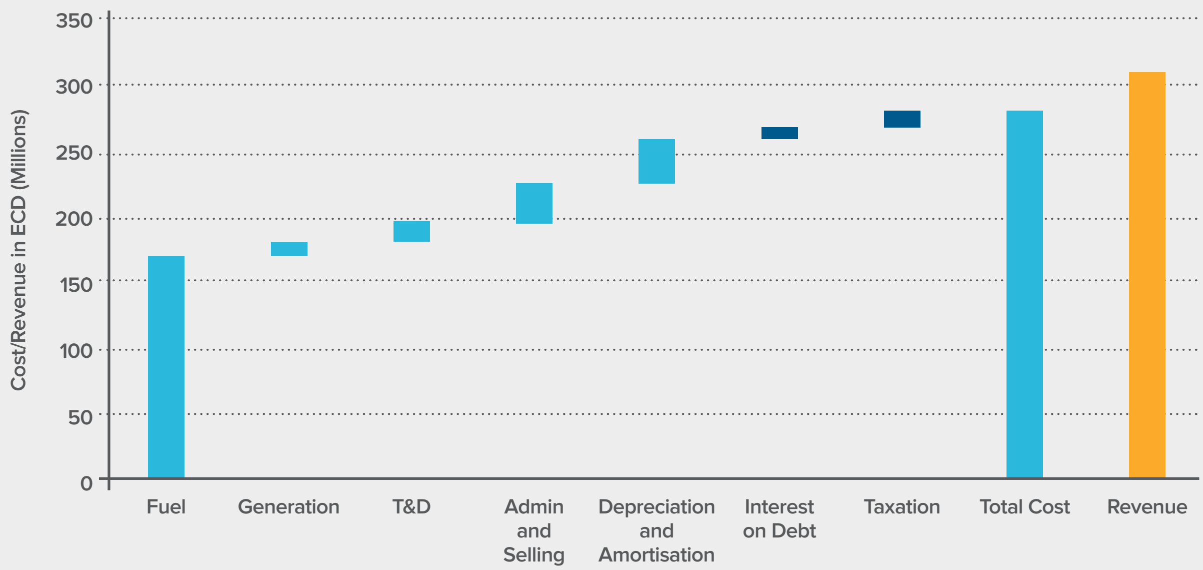
Costs to operate the diesel generators and the transmission and distribution (T&D) systems plus administrative expenses equal approximately EC$230 million (in 2015). These costs vary depending on the cost of diesel fuel, which has historically ranged between 40 and 60 per cent of total expenditures. Average rates for customers have ranged between EC$0.70 and $1.10 per kWh, which according to the regional association of electric utilities (CARILEC) are some of the lowest electricity rates in the region (Appendix J).

LUCELEC, Saint Lucia's electrical utility company and sole provider of electricity, is the responsible and financially sound operator of the electricity system, supplying reliable power to its ~67,000 customers as well as to more than 300,000 tourists that visit the island each year. Reliability of the electrical supply is critical, as it supports economic growth and reduces potential damage from intermittent power (the number of hours of system disruption has dropped 50 percent since 2004 and caused less than EC$3 million in losses in 2015 ). LUCELEC is profitable (11.6 per cent return on equity in 2015) (see Figure 2). The electricity sector also provides stable and high-skilled employment for the island, employing more than 300 people to operate and maintain the power infrastructure.

Challenges to Saint Lucia's electricity system do exist. Saint Lucia's infrastructure is vulnerable to extreme weather events; there are critical points of failure that could leave Saint Lucia without power for days due to high wind and/or flooding events, though historically LUCELEC has reestablished power quickly. In the worst

**FIGURE 2**

LUCELEC COST STRUCTURE AND REVENUE[4]




recent storm (Hurricane Tomas in 2010), LUCELEC was able to re-energise 95 per cent of the system within seven days.

The primary challenge the electricity sector faces is its high dependence on imported fossil fuels, which comes with associated cost volatility and greenhouse gas emissions. In 2014, the Government of Saint Lucia increased previously announced energy targets, setting a renewable energy penetration target of 35 per cent by 2020 (increased from 20 per cent by 2020) and an energy efficiency target of 20 per cent reduction in consumption in the public sector by 2020. iii To reach these goals, implementation of an energy transition process is critical for all Saint Lucian stakeholders. Pressures to address climate change, dropping costs for renewable electricity supply, and demands for more energy efficiency have revealed key challenges, including the regulatory construct, the availability of finance, and the implications of rate structures. Fortunately, recent developments in energy efficiency, renewable energy, cleaner-burning fuels (e.g., natural gas), electricity storage, and advanced controls and metering offer a range of opportunities.

## GENERAL METHODOLOGY

The Government of Saint Lucia and LUCELEC initiated a National Energy Transition Strategy (NETS) process to create a forward-looking strategy to meet the Government's goals and carry out the steps required to pursue the transition. The objectives of the analysis

[iii] Public refers to government-owned facilities.

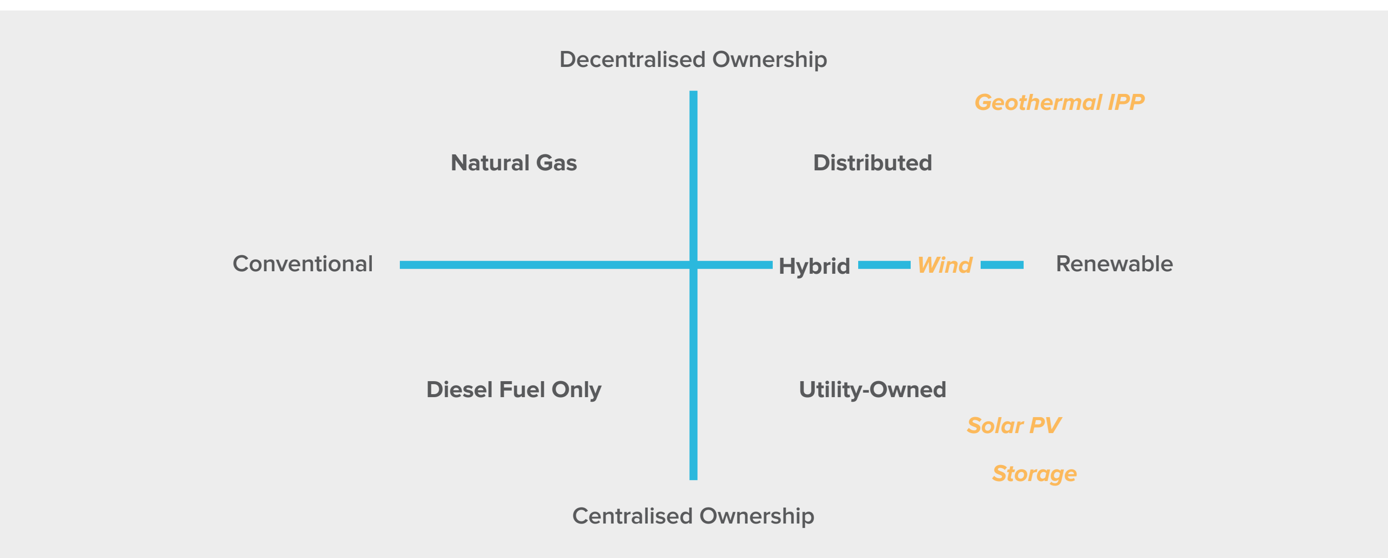
were to explore all potential options for least-cost energy production and consumption, to balance the interest of customers and stakeholders involved in Saint Lucia, and to identify a mix of resources that will meet near- and long-term consumer energy needs efficiently, affordably, and reliably. The analysis process established an integrated resource plan (IRP), typically used by utilities to forecast coming trends and appropriately plan investments to ultimately ensure benefit to ratepayers. Specifically, the IRP identified the optimal set of generation, transmission, and distribution investments that will:

- Improve reliability of the grid
- Facilitate cost containment in a future of volatile oil prices, benefitting the electricity consumer
- Support increased energy independence, including the achievement of renewable energy targets (per the National Energy Policy)

The NETS process, in addition to the technical and economic analyses embodied in the IRP, addresses the broader set of needs required to implement a participatory energy transition, including regulatory reform and redefinition of the utility business model. The process involved extensive data collection, analysis, synthesis, review, and periodic public participation in order to properly inform LUCELEC, the Government of Saint Lucia, public participants, and the National Utilities Regulatory Commission (NURC).

This IRP presents six potential scenarios (prior to selection of the six scenarios, RMI-CWR and partners examined 14 different scenarios and many more sensitivities as well as other technologies not reflected in the six scenarios presented in this document). Each scenario includes a mix of renewable and conventional energy investments planned over the 20-year time period through exploring the implications of different amounts of renewable energy and ownership structures (see Figure 3). Different ownership mechanisms were explored for the wind and solar energy projects proposed for Saint Lucia (either LUCELEC-owned or through IPPs).

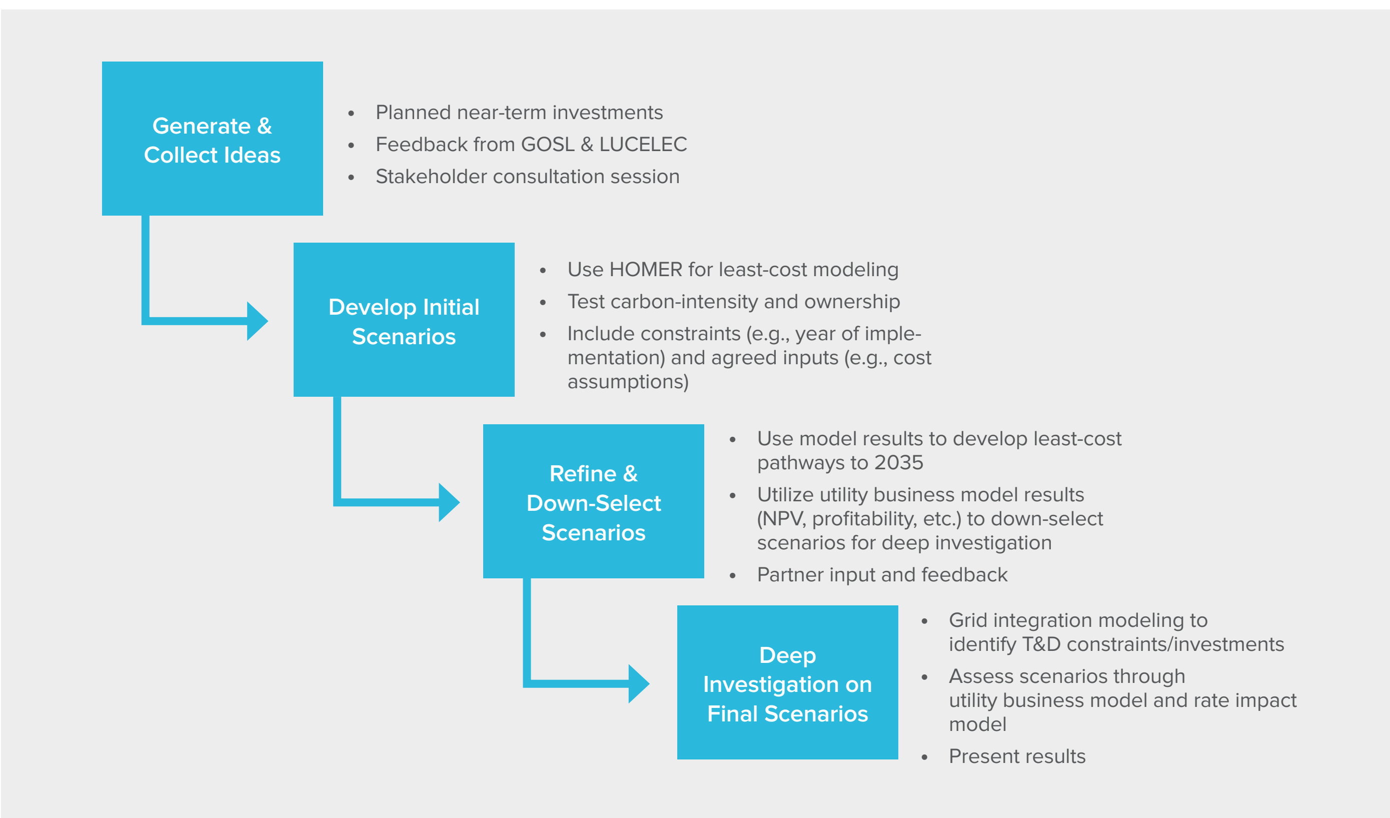
**FIGURE 3**
SCENARIO STRUCTURE



The IRP team organised likely investments together into scenarios based on stakeholder input and then tested the feasibility of each scenario both technically with respect to grid operation and economically with respect to debt, rate impact, and utility profit. External risks such as high or low oil prices were considered through sensitivity analysis considering variable diesel fuel pricing, projected load growth, operating reserve requirements, and other factors. The team used an iterative process to down-select and rank the scenarios, as illustrated in Figure 4.

The primary outcome of the NETS process is the development of a detailed plan created jointly by the Government and LUCELEC, comprised of a set of scenarios detailing how to reliably integrate the optimum mix of conventional and renewable energy technologies into the national electricity grid. The plan will be submitted to the NURC for review, approval, and future refinement (typically electric regulatory bodies are responsible for directing utilities to perform and submit IRPs). This participatory process included a preliminary public stakeholder consultation held in February 2016 (at the Bay Gardens Hotel), ongoing public comment received online, and an intended public consultation session to present the final results.

**FIGURE 4**
ITERATIVE ANALYSIS STRUCTURE



# 02 RESULTS

# RESULTS

Saint Lucia has the opportunity to increase local control and stabilise electricity costs through new indigenous energy generation. Ensuring these benefits requires long-term investments over the coming five years to carefully integrate renewable energy and energy efficiency to complement existing and ongoing diesel generation. While many possible resource mixes exist that meet energy generation requirements and peak demand needs over the coming years, integrating low-cost energy efficiency changes the set of optimal scenarios. Based on these analyses, the IRP presents six scenarios that would meet future loads with required reserves, including high levels of variable renewables.

The requirement to produce sufficient energy for Saint Lucians in the coming years begins to differentiate the scenarios. Figure 5 shows the energy production from various resources in the six scenarios. The difference in energy production between each scenario is due to energy efficiency, which was assessed for all scenarios incorporating investments in renewable energy.

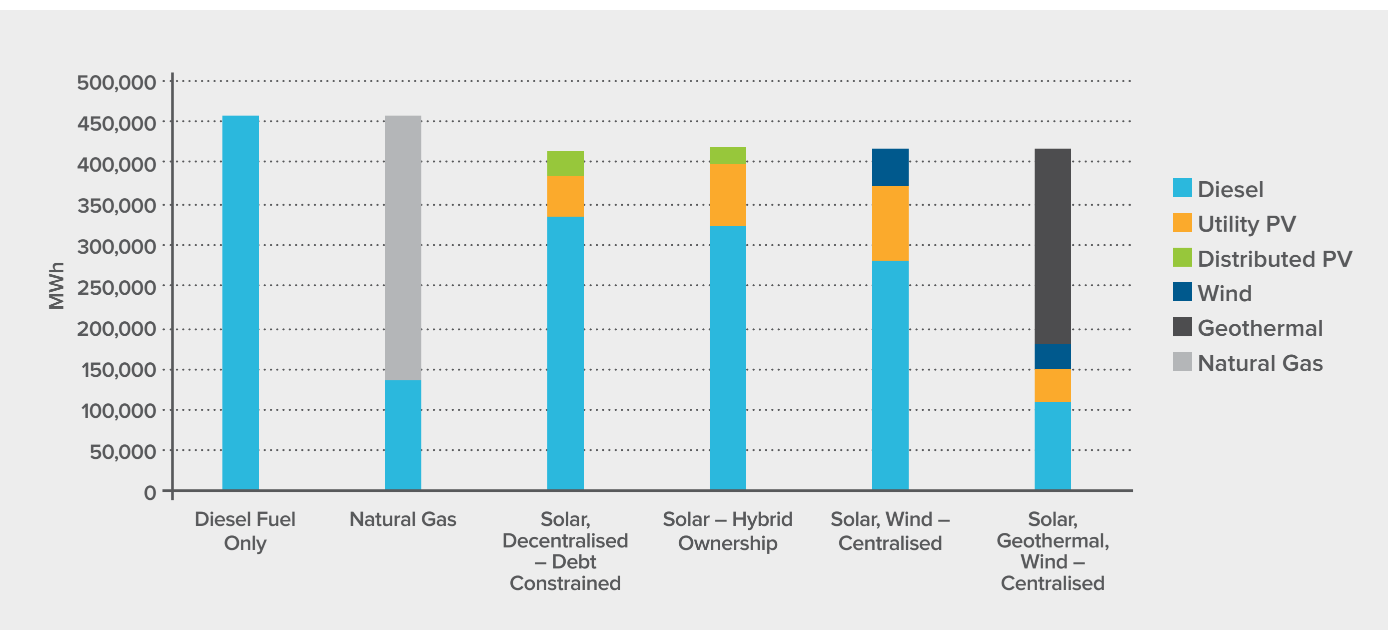
Although all scenarios examined offered merit, one scenario—solar and wind with low levels of distributed generation—met reliability requirements, offered a least-cost scenario, and diversified Saint Lucia's electricity mix away from fossil-fuel dependence. That scenario was closely followed by scenarios including geothermal and natural gas, as both offered benefits over continued diesel usage.

### OPTIMAL SCENARIO

The IRP team finds that a portfolio of diesel, solar, and wind power generation (with storage) offers the best economics with respect to the following metrics: low

**FIGURE 5**

ENERGY PRODUCTION IN 2025 BY SCENARIO



cost to operate the system, lowest rates at the end of the 20-year study period, relatively low debt, and a strong hedge against volatility in diesel fuel prices. This mix is shown to be attainable while providing continued reliability. These results were derived from an hourly simulation over the coming 20 years, performed in the HOMER Energy software.

Seizing near-term opportunities entails installing up to 28 MW of solar PV, developing 12 MW of wind power, pursuing energy efficiency to displace 11 per cent of 2025 load, and adding storage up to 14 MWh. Continuing to operate diesel generation will be critical to maintain grid stability and reserves at low cost, requiring ongoing investment for overhaul and routine maintenance (as well as spare parts and backup generation in the case of unplanned generator outages). However, with energy storage, the system will remain stable even with outages of the largest generator, either diesel or geothermal, according to DNV GL grid integration studies. Adding geothermal at 30 MW is technically viable, but not currently part of the optimal scenario, due to cost considerations. Geothermal, if secured at PPA prices at or below EC$0.38/kWh, would become part of the optimal scenario.

LUCELEC should own the majority of the solar, and be equity partners in both the wind and geothermal developments. This approach, leveraging LUCELEC's expertise and low cost of capital, will result in the lowest rate situation for Saint Lucian customers. Third-party renewable energy developers and customer-owned solar have a part to play, of up to 35 per cent of the total solar installed under this plan, but LUCELEC as the primary owner will benefit the country through lower rates and equitable sharing of costs among all customers.

**GEOTHERMAL**

As the largest examined project, either a 15 MW or 30 MW geothermal project would provide renewable and dispatchable power, with the potential for a cost-effective pathway to energy independence. A 30 MW geothermal facility would provide almost 60 per cent of 2025 energy generation needs, and could integrate into a portfolio of solar, wind, diesel, and storage to provide reliable power. Because of geothermal's significant required investment and specialized technology, Saint Lucia is exploring the geothermal resource with the intention of procuring a power purchase agreement (PPA) in partnership with developer Ormat International.

Though the Caribbean boasts promising resources, securing geothermal cost-effectively requires consistent and focused engagement with the developer team to advance feasibility studies and prove the resource with preliminary drilling, typically using exploration wells. Grant or concessional financing can support the initial at-risk phase, and ultimately reduce the cost of the project. Reaching agreement on PPA terms requires an informed discussion between the developer and utility off-taker. Creating regulatory certainty supports a smooth and productive process. For Saint Lucia, these activities are well underway, and offer a promising route to low-cost geothermal.

Electric vehicles have potential as a grid asset, if electric vehicle (EV) penetration increases and if programs are put in place to incentivise charging in a way that optimises the electricity system.[iv]

[iv] Utilizing controlled charging (and eventually discharging) from EVs allows for improved system operation through use of the vehicle battery for frequency response and load shaping.

In summary, this optimal scenario offers the following benefits:

- 13 per cent less total cost to operate in the coming 20 years, while ensuring continued LUCELEC profitability (average return on equity of 11 per cent) and allowing for limited customer participation, specifically ownership of distributed PV up to 1 MW. Economic and grid integration results show additional customer participation to be possible, but ensuring all ratepayers benefit requires active management from the NURC.
- Lower and more stable costs across all considered fuel price forecasts.
- 19 per cent renewable penetration (by energy) by 2020 (by capacity, this generation mix reaches 71 per cent if government prefers to use this metric as part of the National Energy Policy).
- Managing higher debt loads will be critical, but regulatory certainty, leading to LUCELEC profitability, will allow confidence from lenders (existing covenants should be examined closely).
- LUCELEC participation in wind and geothermal projects will ensure technical validity of the projects and provide for a solvent utility into the future, helping to guarantee reliable electricity.

However, any energy transition also involves challenges. Project development takes time, careful due diligence, and the involvement of many stakeholders. Embarking upon larger energy projects for new technologies adds to the burden. Securing low-cost debt (this analysis presumed 8 per cent interest rate on new debt, but much cheaper [in the range of 4.5 per cent] is possible through the Caribbean Development Bank [CBD]) will be critical to achieve good economic results and to ensure the debt burden doesn't become untenable. Also, ensuring regulatory clarity will help provide low-cost debt for Saint Lucia and LUCELEC.

Other critical issues include training and developing staff, and acquiring land for new technologies. Land acquisition can be difficult, particularly for highly visible technologies (such as wind), and any technologies that restrict other economic activities (e.g., ensuring land for agriculture). Additional costs were factored into the model to account for securing the appropriate land for solar and wind. Solar sites appear feasible (see Appendix O), but it is important to ensure that solar does not limit future commercial or agricultural development.

## ENERGY RESULTS BY SCENARIO

First and foremost, all scenarios must provide adequate capacity to meet peak demands as well as reserve requirements. For the coming years, all scenarios will depend primarily on diesel to perform this function, with other resources supplementing that resource. However, multiple scenarios add additional capacity, both firm and variable capacity, to lower overall system costs, not to meet peak demand requirements. This addition of new capacity for lowering costs—rather than meeting load growth pressures—opens a new paradigm for the utility. Figures 6 and 7 show the modeled installed capacity of various resources in the six scenarios, several of which show expansion from the current installed capacity base.

Diesel capacity is planned to shrink slightly, with planned retirements (see Appendix D for more information). These retirements will be able to proceed as planned, per the load forecasts documented below.

### LOAD FORECAST

By assessing both near term through specific projects and long term based on projected gross domestic product (GDP) and ensuing electricity demand growth,

**FIGURE 6**

INSTALLED CAPACITY IN 2025

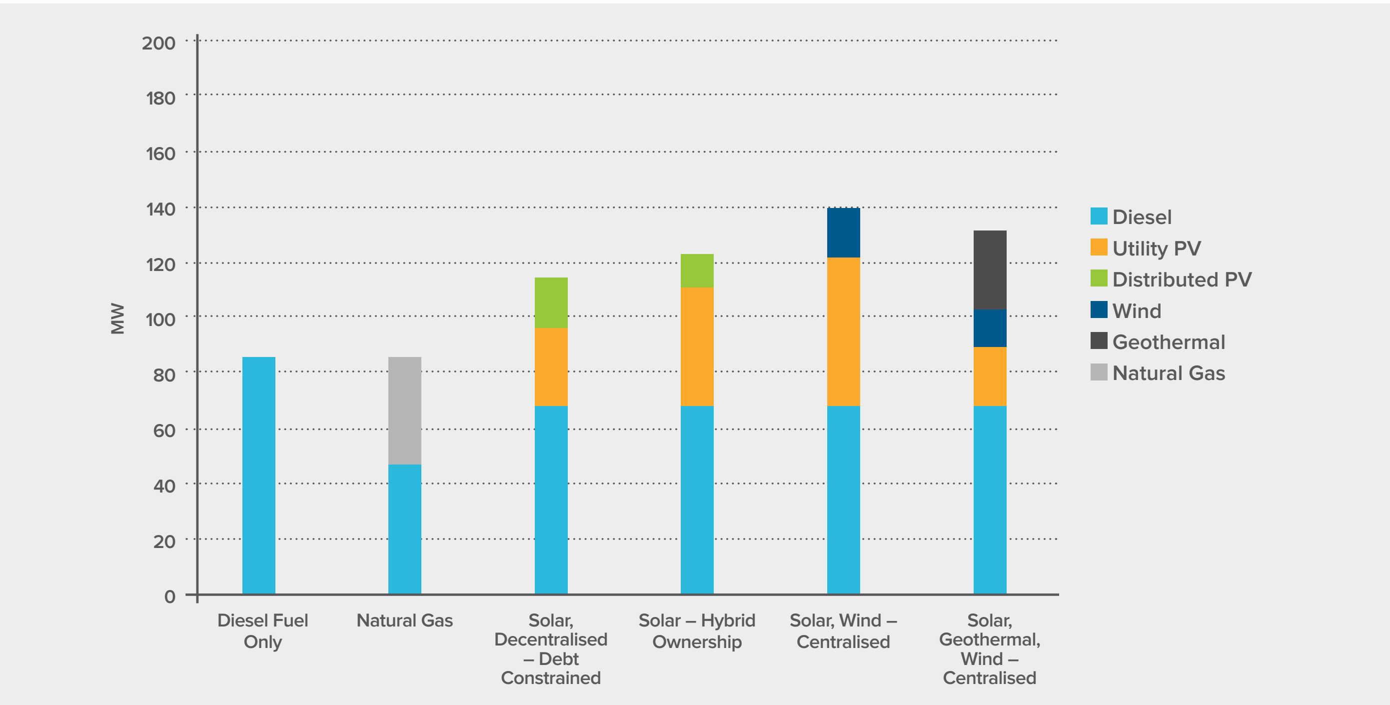
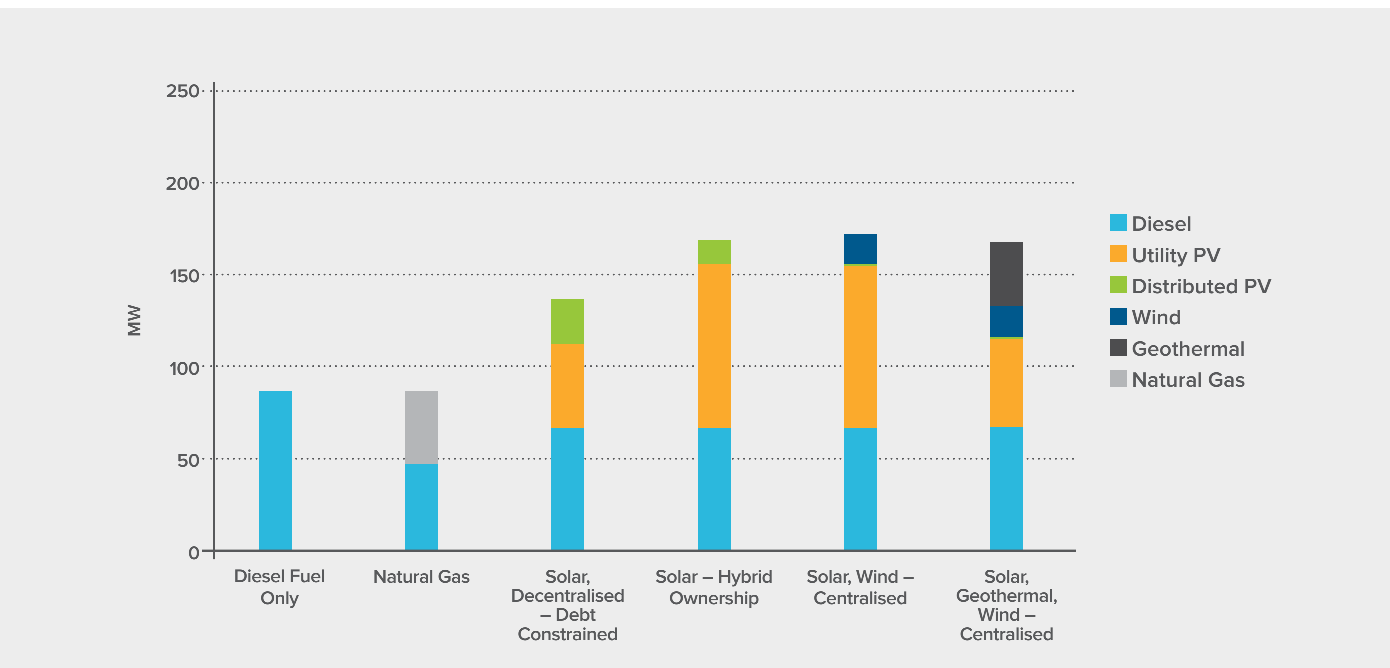



**FIGURE 7**

INSTALLED CAPACITY IN 2035



the analytical team developed a national load forecast for 20 years (from 2015 to 2035). The results of this exercise are shown in Figure 8.

Loads are expected to grow from approximately 340 million kWh in 2015 to approximately 440 million kWh in 2035 (under the base scenario)—equivalent to a 1.32 per cent year-over-year growth rate. Higher and lower scenarios were explored (see the Sensitivity Analysis section below).

Peak loads, shown in Figure 9, are expected to grow from 59 MW in 2015 to 85 MW in 2035, requiring additional generation. Based on the reference case load forecast, new generation (in addition to the current diesel generators) will be required in 2023.

### ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

Regulators and utilities around the world have employed demand-side management (DSM) to reduce peak demand, defer generation and T&D investments, and benefit consumers by reducing electricity consumption. Broadly, some common examples of DSM include energy efficiency (using less energy to perform the same task), demand response (reducing

**FIGURE 8**

LOAD FORECAST WITH ENERGY EFFICIENCY

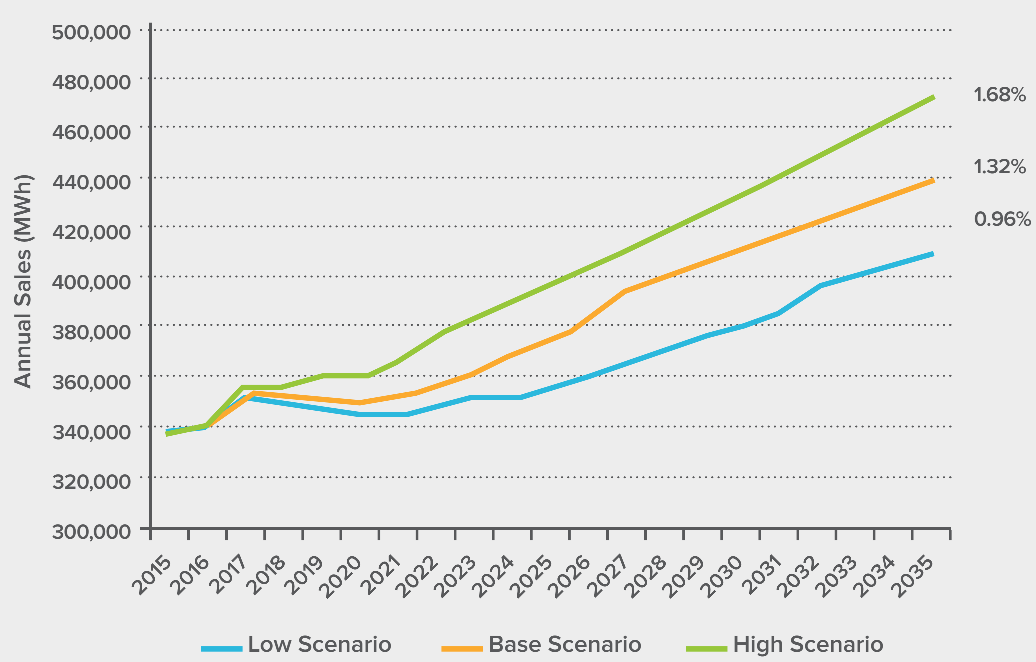
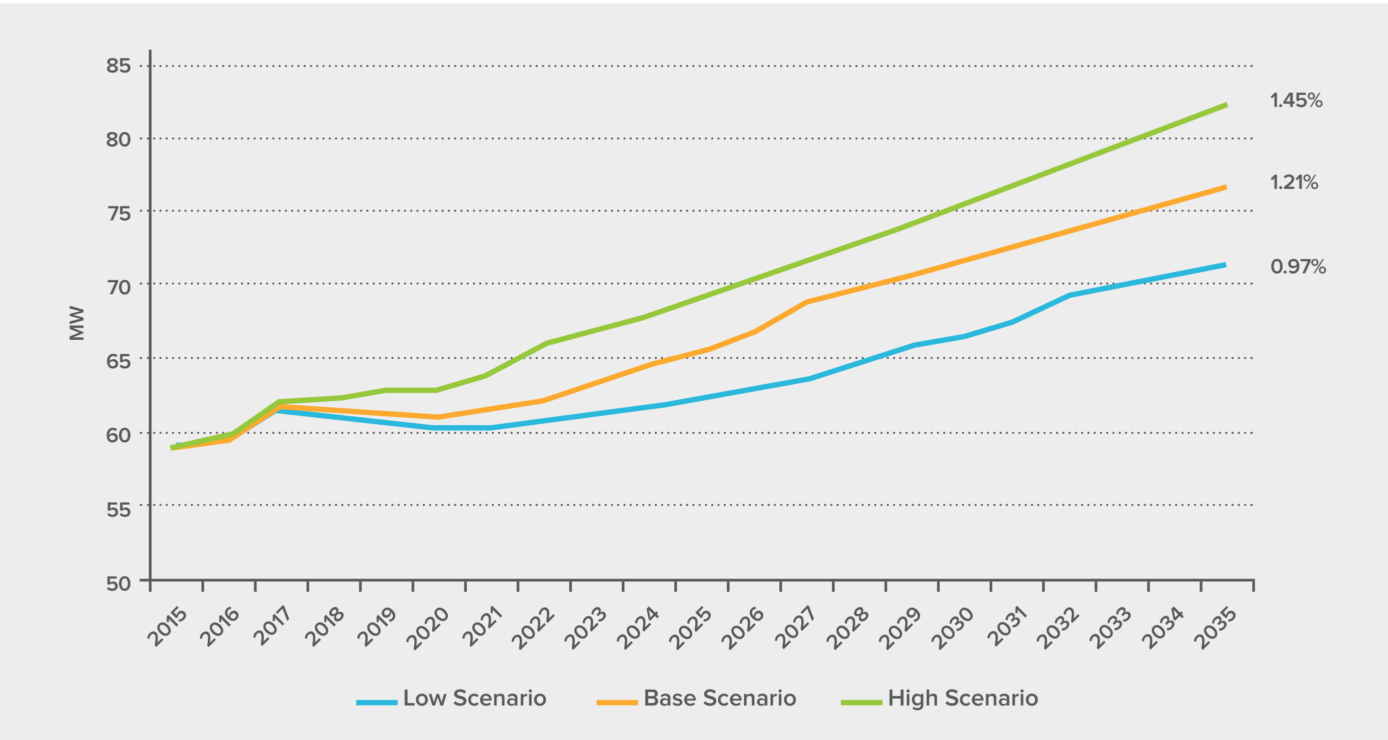


**FIGURE 9**

LOAD FORECAST—PEAK DEMAND




demand on the customer side in order to respond to an event or condition within the electricity system), and load shifting (not reducing overall energy use, but shifting the time of use to an off-peak period). This analysis focuses on energy efficiency, specifically retrofits and equipment upgrades to reduce end-use energy consumption for residential, commercial, and hotel customers as the lowest hanging fruit for Saint Lucia.

Compared with energy generation options, energy efficiency is the cheapest resource examined in the analysis, with a levelised cost of EC$0.14 to $0.19 per kWh. Seizing this opportunity requires developing a programmatic approach; targeting residential, commercial, and hotel customers for energy efficiency upgrades; and enacting an island-wide swap-out of existing streetlights and replacing them with LEDs. Energy efficiency technologies included new technologies for cooling (highly efficient air conditioners), lighting (LED lighting systems), refrigeration (highly efficient refrigerators and freezers), water heating (including solar thermal water heating), audits of existing equipment, and behavioral savings.

A baseline assessment determines the breakdown of end-use electricity consumption for residential, commercial, and hotel customers, in order to target the areas of highest energy efficiency potential for each sector. Unit energy consumption and equipment saturation on the island were adapted from a recent DSM study performed by DNV GL on another Caribbean island-nation and adjusted to the Saint Lucian context. The following end-use breakdowns, shown in Figure 10, reveal the top areas of electricity consumption among Saint Lucians.

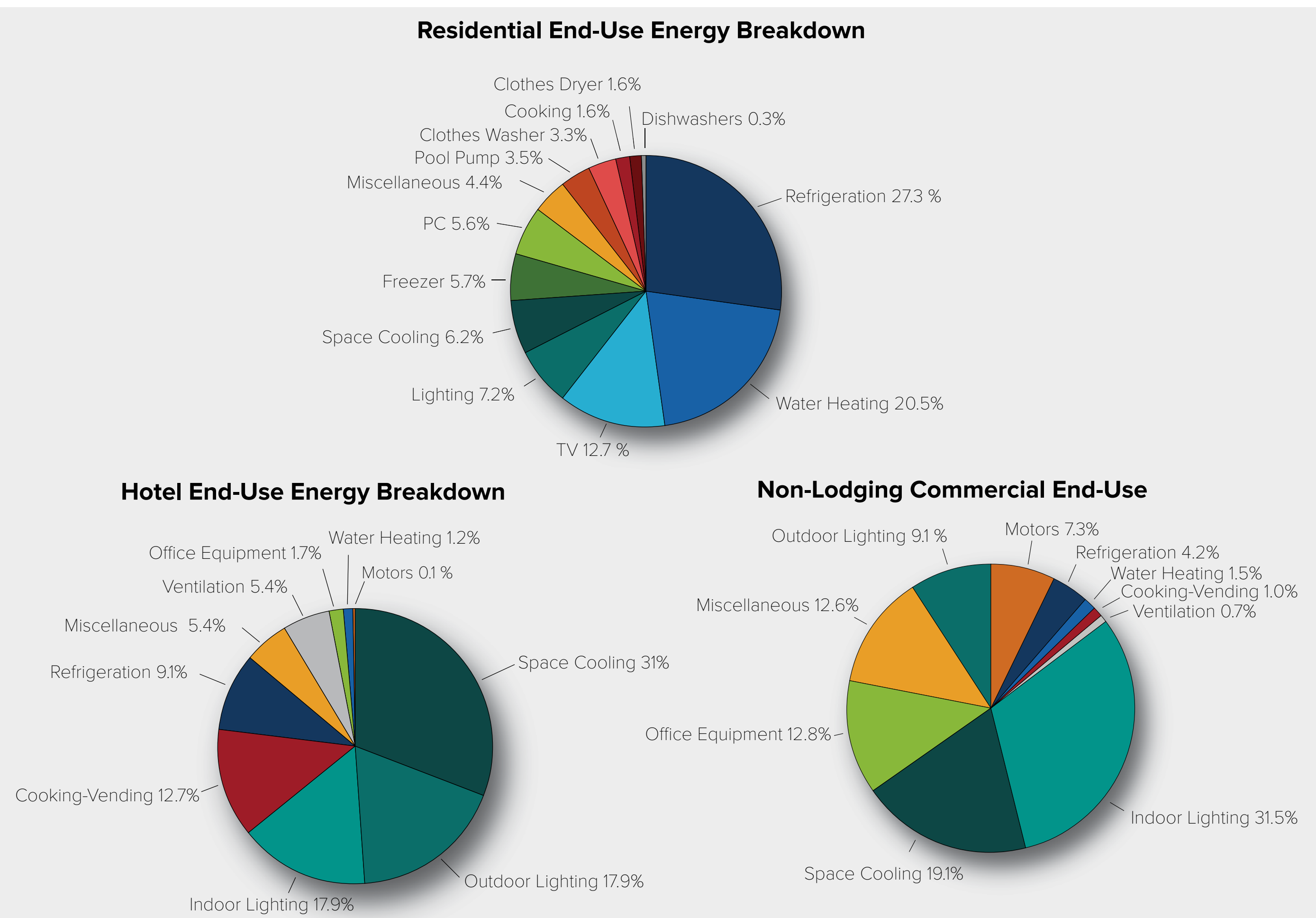
For the residential sector, the largest loads are refrigeration and water heating, which account for nearly half of consumption at 47.8 per cent, followed by television sets, lighting, and space cooling (the latter three together use a total of 26.1 per cent of household energy use). Lighting and space cooling make up 50.6 per cent of non-lodging commercial energy consumption and 64.4 per cent of hotel energy consumption. The majority of these large energy users are suitable targets for an energy efficiency program aimed at replacing inefficient equipment at the end of its useful life.

With a targeted energy efficiency program, LUCELEC has the potential to reduce annual energy consumption by over 10 per cent from the baseline in 2035 (approximately 50,924 MWh cumulative annual savings). These savings would occur through a targeted energy efficiency program offering incentives to customers who choose efficient technologies, and focused on the following sectors:

- Residential: 23,507 MWh savings from lighting, refrigeration, cooling, water heating, and other retrofits

**FIGURE 10**

END-USE BREAKDOWN BY CUSTOMER CATEGORY



- Commercial: 13,107 MWh savings from lighting, refrigeration, cooling, and other commercial loads addressed during an energy audit
- Hotels: 8,330 MWh savings from lighting, cooling, refrigeration, and other upgrades
- Street lighting: 5,978 MWh annual savings from LEDs

These savings are commensurate with the findings of numerous energy efficiency audits performed on Saint Lucian facilities by Dr. Frederick Isaac of Energy & Advanced Control Technologies Inc. (EACT). The measures considered in the analysis are phased in evenly over their unit lifetimes (e.g., 15 years for refrigerators or 10 years for water heaters) except for indoor lighting, which is recommended as a special program implemented within three years' time as indoor lights are the lowest cost and the easiest swap-outs for all customers. The existing high-pressure sodium (HPS) streetlights should also be replaced with LED streetlights, and LUCELEC and the government have already initiated discussions toward a two- to four-year retrofit timeline.

A comprehensive residential, commercial, and hotel energy efficiency program (excluding streetlights) would cost approximately EC$12.4M per year in the initial years and fall steadily to EC$ 2.5M in year 15, the final year of program implementation when all energy-efficient units are phased in. A swap-out of HPS to LED streetlights would be an additional but separate cost of EC$6.6M per year over the first four years. In total, the 15-year cost would amount to approximately EC$120M. The cost of the energy efficiency program to LUCELEC—or an alternative implementation agency—would include incentives as well as program administration and marketing, further explained below.

The project team based cost estimates on experience from a similar study recently done by DNV GL for another Caribbean island and adjusted for currency. Costs consist of three components:

1. **Incremental measure costs** are costs associated with the DSM measure, either higher efficiency or change in technology, compared to what would have been bought and installed without any incentives. For example, if a more efficient LED lamp is $33.74 versus $2.77 for an incandescent lamp, the initial incremental cost is $31.03.[v] Incentives such as rebates are typically a portion of the incremental cost.[vi] Typically, projections are based on 50 per cent, 75 per cent, or 100 per cent of incremental costs, with adoption proportional to the per centage of incremental cost paid. For this analysis, a 100 per cent incentive is assumed (a conservatively high estimate of program costs).
2. **Administrative costs** are costs associated with operating DSM programs that provide some form of market initiatives, including education, program tracking, and evaluation. These are typically for internal staff and contractors who help implement the programs.
3. **Marketing costs** are costs associated with promotion of the DSM programs, including advertising and events and workshops for vendors, trade allies, and end-use customers.

Administrative and marketing costs can each vary from 5 to 10 per cent of total program costs. For purposes of this study, administrative and marketing costs are assumed as 7.5 per cent each of program costs. As is done with many utilities in the U.S., LUCELEC, with its existing customer relationships, is well

[v] Accounting for differences in lifetimes, since an incandescent lamp lasts only 1,000 hours, versus 25,000 hours for an equivalent LED lamp.
[vi] Incremental cost refers to the premium for the efficient alternative versus the standard offered technology (such as an appliance).

positioned to deliver such an energy efficiency program. This program should initially focus on replacing inefficient equipment with efficient equipment. However, given the current rate structure, energy efficiency would be seen as lost revenue and LUCELEC would therefore need to be compensated or made whole if it were to lead such a program. The NURC can provide financial incentives to LUCELEC to pursue energy efficiency or work with LUCELEC to develop a new business model that enables this energy efficiency program through rate design.

### RENEWABLE ENERGY

The team considered a diverse set of alternative energy generation resources. These technologies and fuels included solar photovoltaic, on-shore wind energy, biomass, waste to energy, geothermal, ocean thermal, natural gas, heavy fuel oil, and liquefied petroleum gas (also known as propane). Non-generation technologies were also considered, such as electricity storage through lithium-ion battery storage or electric vehicles, submarine cables to nearby islands (Martinique and Saint Vincent and the Grenadines), and demand response through backup diesel generator control or controllable customer loads.

Ultimately, the analysis team focused on a set of proven technologies (with operating examples in the region) that can be procured at reasonable cost. These were diesel, solar, wind, geothermal, natural gas, energy efficiency, and electricity storage.

Wind and solar energy both have strong potential and viable sites for them exist. While operating a grid with a high penetration of variable renewables is technically possible, once renewable penetration reaches 70 per cent , the costs increase exponentially due to pressure on diesel generators (ramping and reserve margin), the amount of storage required, and decreased capacity utilisation (due to increased spilled energy). Achieving renewable penetration above 50 per cent before 2025 is also costly due to the long development time of geothermal.

However, a high-penetration renewable future is possible. It requires exceeding energy efficiency targets to minimise total installed capacity required, demand response—providing utility control over critical loads—to reduce storage required, and achieving better-than-expected cost reductions for solar PV and storage. Energy storage plays a role in stabilizing the system by meeting peak loads, reducing spilled renewable energy, supporting reserve capacity, and improving diesel generator efficiency by almost 1 per cent in a future system that includes various renewable resources.

### SOLAR

In regard to solar generation, land availability does not appear to be a limiting constraint, although competition for viable land will increase the price of solar projects. In an island context, land is critical; therefore, the costs for long-term land procurement were estimated and added to the projected cost of solar installation in this analysis. A solar resource assessment was performed across the entire island to determine potential ground-mount locations for future solar projects as well as potential rooftop and parking structure sites for larger-sized distributed PV systems.[vii] Appendix O contains more details. Sufficient land exists to site 380 MWdc of solar power. That generation would require seven square kilometres, split across 26 sites. Each of those 26 sites has been screened for viability and non-competition with other development activities.

[vii] The study, performed by DNV GL, included national topography data, building footprints, parcels maps, and other data sources, and was vetted by LUCELEC, the Government of Saint Lucia, the Forestry Department, the Agriculture Department, and Invest Saint Lucia.

Commercial rooftop and parking lot opportunities are also abundant—with 27 MWdc of potential across 42 parking areas and 26 commercial buildings. Many other sites (including residential rooftops) will be possible for solar generation, giving solar a high potential for contributing to Saint Lucia's renewable energy goals. Figure 11 highlights top sites that were identified for potential parking lot, rooftop, and ground-mounted solar PV. Additional detail has been provided to the NURC as part of its ongoing role in determining the appropriate future solar projects for Saint Lucia. Reliability of the grid when operating with new variable resources such as solar is critical, and a new challenge under varying weather conditions. In addition to the full grid integration study documented below, the analysis team examined how solar and storage mixes respond to variability in solar output due to cloud cover (see Appendix P for more information).

**FIGURE 11**

TOP IDENTIFIED SITES FOR SOLAR DEVELOPMENT (MORE DETAILS IN APPENDIX O)


Parking Lot Points of Interconnection (POIs)
Rooftop POIs
Ground Mounted POIs

## WIND

The integrated resource plan analysis incorporated wind energy potential based largely on the preliminary analysis and development of a 12 MW wind farm near Dennery Bay north of the Praslin substation (on the east coast of Saint Lucia). Crown land near the road and near the transmission line is intended to host the wind project. The proposed approach places turbines on the ridgeline, and incorporates the cost of a new substation (presumed to include one transformer between 12 and 15 MVA) as well as the cost of additional 66 kV transmission lines. Based on RMI-CWR analysis of the time required to procure the equipment needed for a major wind project, the earliest potential date for full operation of the wind farm is the start of 2019.

Cost: The wind project costs were estimated based on industry experience and similar projects in the region. The capital cost was estimated to be EC$7,840 per kW in 2015, decreasing over time (per industry projections) to EC$7,076/kW in 2025. Operating and maintenance costs were assumed to be EC$140/kW per year.

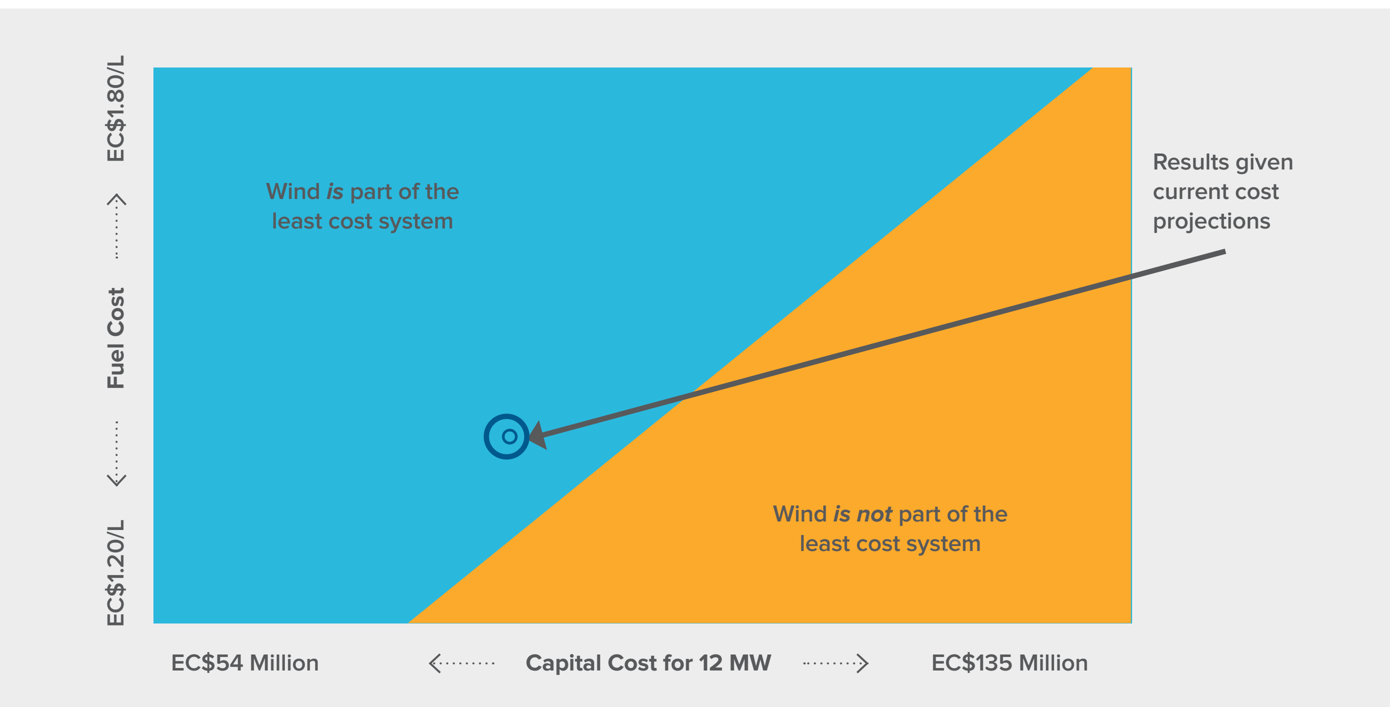
The team assessed two approaches to financing the wind project:

1. Structure the deal as a PPA with the expected price of EC$0.49 per kWh.
2. LUCELEC develops and finances the wind project (using a special purpose vehicle). This approach would require buying out the existing developer for the wind project (WindTex), a feasible option considering LUCELEC is a part developer.

These scenarios were explored as different approaches to renewable generation ownership.

**FIGURE 12**

WIND SENSITIVITY ANALYSIS (CAPITAL COST VS. DIESEL FUEL COST)



Based on LUCELEC's likely financing structure, the integrated resource plan found LUCELEC to be the preferred owner of the wind project (leading to the maximum benefit for ratepayers). Adding LUCELEC-owned wind to a cost-effective portfolio of diesel, solar, and storage causes a 1 per cent reduction in the total cost to operate (over the coming 20 years). That translates into $54 million in lower operating costs.

If, however, the negotiated PPA price is below EC$0.38, the third-party developed option becomes the least-cost pathway for wind. Due to continued load growth, an additional 6 MW of wind energy become cost-effective in 2026 (reaching a total of 18 MW of wind installed in the 20-year timeframe).

Figure 12 shows a wind sensitivity analysis, highlighting when wind is and is not part of the least-cost system given a range of capital costs for the wind project and cost for diesel fuel.

### GEOTHERMAL

The largest project examined in the integrated resource plan is a 30 MW generation station for geothermal, as is currently under negotiations with Ormat International, an energy developer based in Nevada. A 15 MW plant was briefly examined, but the 30 MW plant became the focus for the project (due to economies of scale reducing costs and suiting the projected load profile with no excess generation). This 30 MW project would be located in Soufrière and would involve test drilling (to verify the resource), production wells (dug where the resource appears greatest to provide steam), re-injection wells, and generators, as well as a substation including two transformers.

This project, as currently proposed by the developer (between EC$0.41 and EC$0.49), is not economically advantageous for the country and adds almost 3.5 per cent to the total cost to operate the system in the coming years (when compared with a portfolio of continued diesel, solar, and storage). Alternatively expressed, this project would cause Saint Lucia to spend an additional EC$186 million to operate the electricity system in the coming 20 years.

Analysis performed for the integrated resource plan indicates that a cost below EC$0.38 per kWh for the PPA price (with no escalation factor) would make this a beneficial project for Saint Lucia. This assessment does not capture the value of avoided carbon emissions (geothermal allows for much deeper cuts to carbon emissions) or the stability and control provided by using indigenous resources (often considered to be the cost of energy security).

Typical mechanisms to reduce the cost of the geothermal development are twofold, the financial and the technical. The financial begins by securing concessionary financing (from the World Bank or from the United States). For large investment projects such as this one, securing low-cost capital can greatly reduce the resulting PPA price and benefit Saint Lucians through lower electricity prices. At a technical level, the upcoming test drilling and production well

drilling will be costly. Reducing this cost by using a diamond core drill bit rig to dig deep slim holes avoids the larger cost of bringing an oil and gas-drilling rig to Soufrière, which costs between EC$16M and $22M per well.

Reducing and managing the technical and financial costs can put geothermal on a pathway to providing low-cost power and benefitting the country. The IRP recommends continued pursuit of the geothermal resource, and the five-year plan (detailed below) includes consideration of how investments in other generation should occur before 2024 to avoid interfering with the economics of geothermal.

### CONTINUED THERMAL GENERATION

The ongoing operation of thermal generation (specifically the diesel generators located at Cul de Sac station, whose capacities are plotted in Figure 13) is critical to providing low-cost and reliable electricity. In the recommended scenario, 66 per cent of electricity generation (in kWh) would come from seven generators (generators 4 through 10) in 2025 (see Appendix D for more information on these generators). Generators 1 to 3 (the oldest and the least efficient) are currently overdue for retirement and can be decommissioned in 2019. Generators 4, 5, and 6 will be due for retirement in 2023, but can be extended with overhauls if required. By 2018, the recommended scenario proposes supporting existing diesel with a total of 14 MW of solar and 6 MWh of storage (able to provide 18 MW of instantaneous capacity).

As seen in Figure 14, generators 1 to 3 are used infrequently in today's system, but provide critical reserve capacity (allowing LUCELEC to meet n-2 conditions—the ability to meet loads if the two largest generators are unavailable). As seen in Appendix F, both operating reserves and n-2 conditions (supported by new electricity storage) will be sufficient even after decommissioning generators 1 to 3 when new alternative resources are added to the system.

Under the reference case, retiring generators 1 to 3 requires limited replacement (a 6 MW new diesel generator installed in 2017) and new generation is

**FIGURE 13**
DIESEL GENERATOR OUTPUT

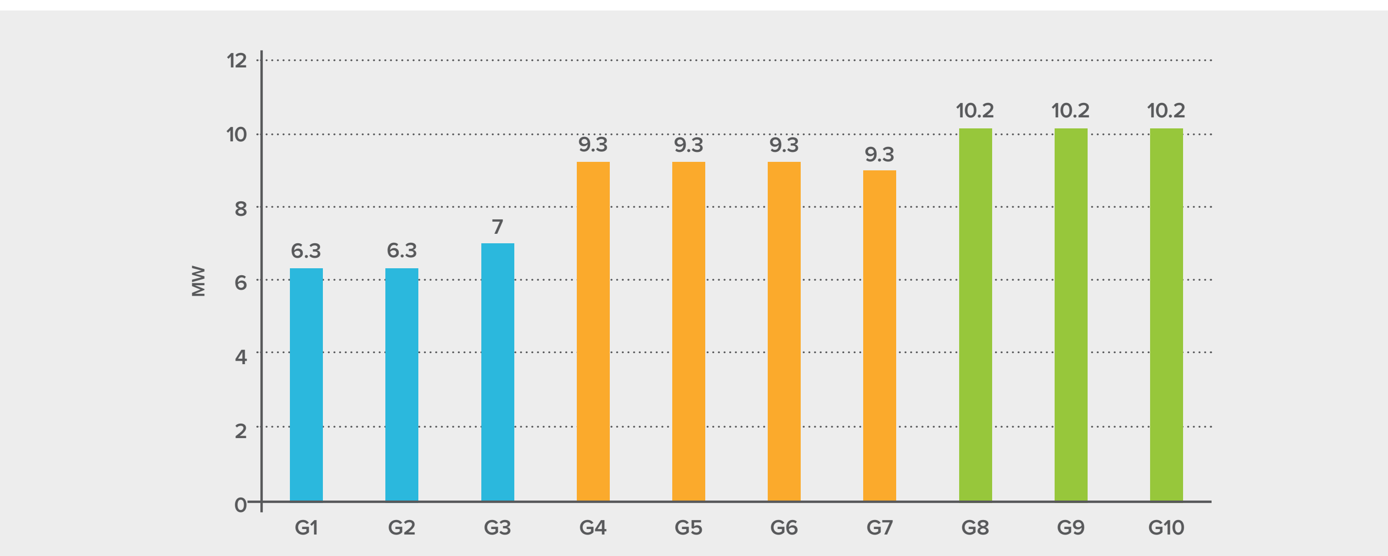
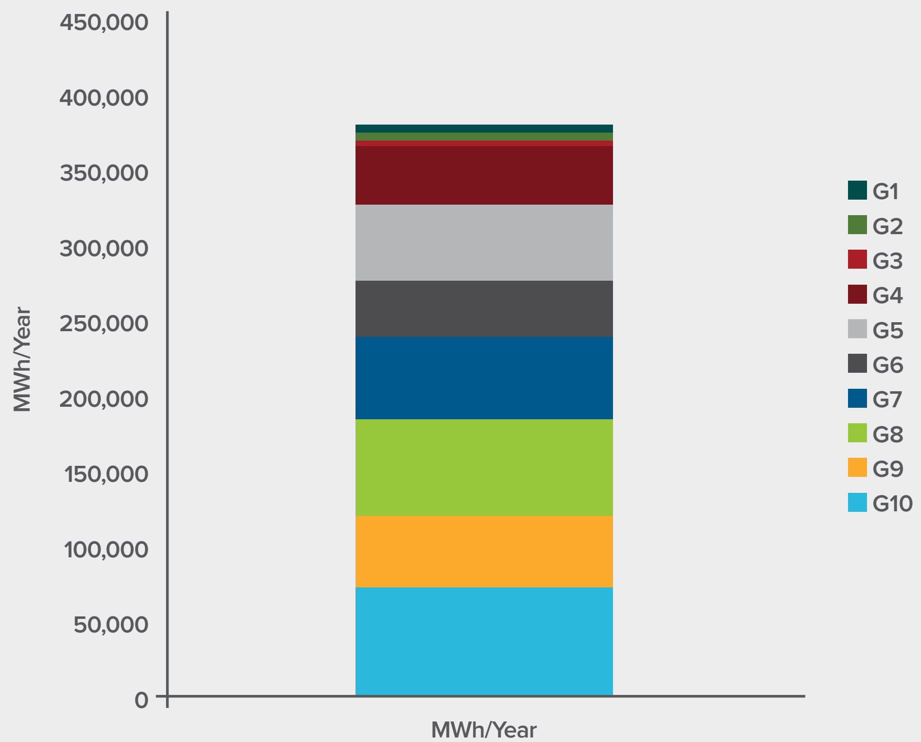


**FIGURE 14**

ANNUAL DIESEL PRODUCTION (MWH) IN 2015 BY DIESEL GENERATOR




required further in the future (one new 12.4 MW diesel generator installed in 2023).

Ongoing overhauls and overhead and maintenance (O&M) of generators (including an inventory of spare parts) provide a financial incentive to decommission generators, but continuing to operate diesel provides a cost-effective generation and reserve source. This trade-off is considered in the scenarios examined, which include operation and maintenance costs for all resources included in each scenario.

Dispatching of the current generators was presumed to follow economic order, with the most efficient generators being deployed at or near peak efficiency (depending on what is needed to meet operating reserve requirements). When operating, each generator always operates at or above 70 per cent of its rated capacity. One example weekday (Figure 15) and weekend (Figure 16) dispatch chart demonstrates how the diesel generators might be dispatched in the fossil-fuel only reference case (in 2025). Note that by 2025, the IRP modeling includes a new diesel generator in the fossil-fuel only reference case, as discussed above; this generator is designated as G11 in the dispatch charts below.

### NEW THERMAL GENERATION (NATURAL GAS)

Natural gas has long been promised as a thermal generation option for Saint Lucia (and the Caribbean).[viii] The lower commodity price of natural gas compared with diesel creates a potential to reduce total cost to operate at certain price points, as shown in Figure 17. However, the significant development time, required regional collaboration, exposure to volatile gas costs, and risk required for a long-term contract make this an unattractive option.

Currently, most natural gas exports occur from oil producers (Russia, Norway, Qatar) via pipelines or high-volume ocean-faring carriers. U.S. exports of

**FIGURE 15**

SAMPLE WEEKDAY WITH 2025 GENERATOR DISPATCH

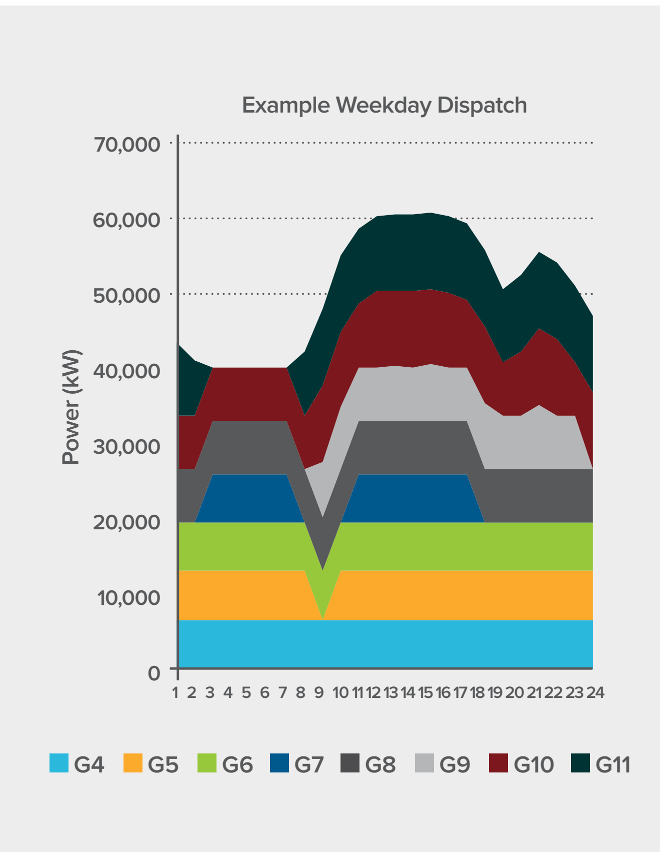
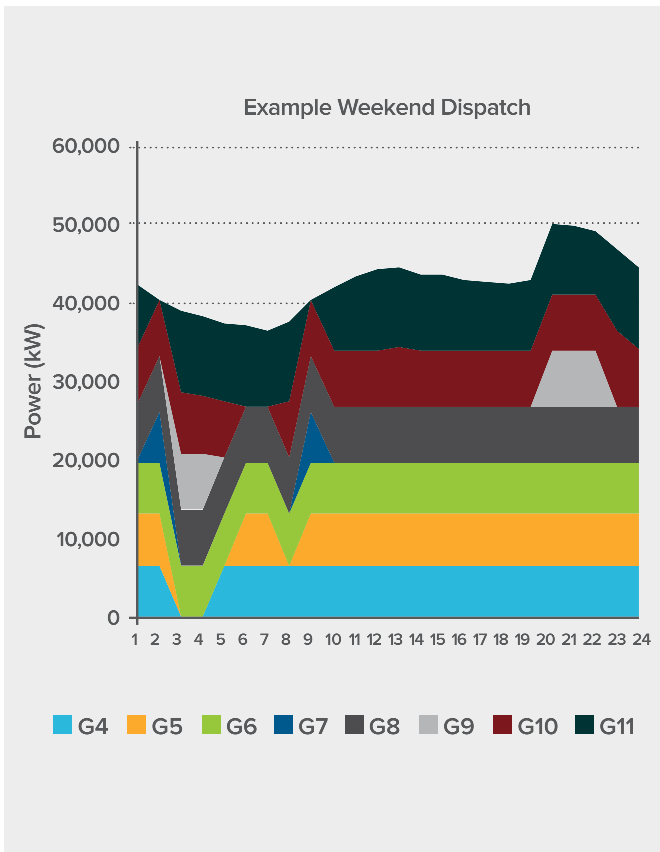



**FIGURE 16**

SAMPLE WEEKEND WITH 2025 GENERATOR DISPATCH




[viii] Natural gas refers to a mixture of gases, primarily methane, found in rock formations and produced by the decomposition of organic matter. Most natural gas is extracted specifically, or as a byproduct of petroleum extraction.

natural gas started in early 2016 in earnest, and U.S. businesses and government actors are looking to export more, including at volumes appropriate for island nations (categorised as "very small" for natural gas volumes).

Right now, the Dominican Republic, Trinidad and Tobago, Puerto Rico, and Jamaica use varying amounts of natural gas for their power generation (Barbados imports natural gas, but for consumer use only). Potential exporters of natural gas to the Caribbean include the United States, Canada, Mexico, Venezuela, and Trinidad and Tobago, or re-export from the Dominican Republic or Puerto Rico.

Cost estimates (provided by suppliers and independent consultants) vary widely, due in part to the small scale of Saint Lucia's requirements for natural gas volume. Further detail about the analysis undertaken in the NETS process for natural gas is included in Appendix M. Figure 17 displays the revenue requirement of LUCELEC for a system that continues to use diesel fuel,[ix] and for one that transitions some of the existing generators to run on natural gas, at three different cost estimates.

Depending on the cost of setting up the infrastructure (including the receiving terminal—estimated to be approximately one-fourth of the total cost and approximately EC$160 million for generator retrofits[x]) and the cost of natural gas (approximately EC$25 per MMBtu including transportation, export infrastructure, and operations), LUCELEC's projected revenue requirement for a system using natural gas is lower than for a system that continues using all diesel fuel for electricity generation. When translated into rate reduction, gas creates rate relief comparable to the best renewable energy options.

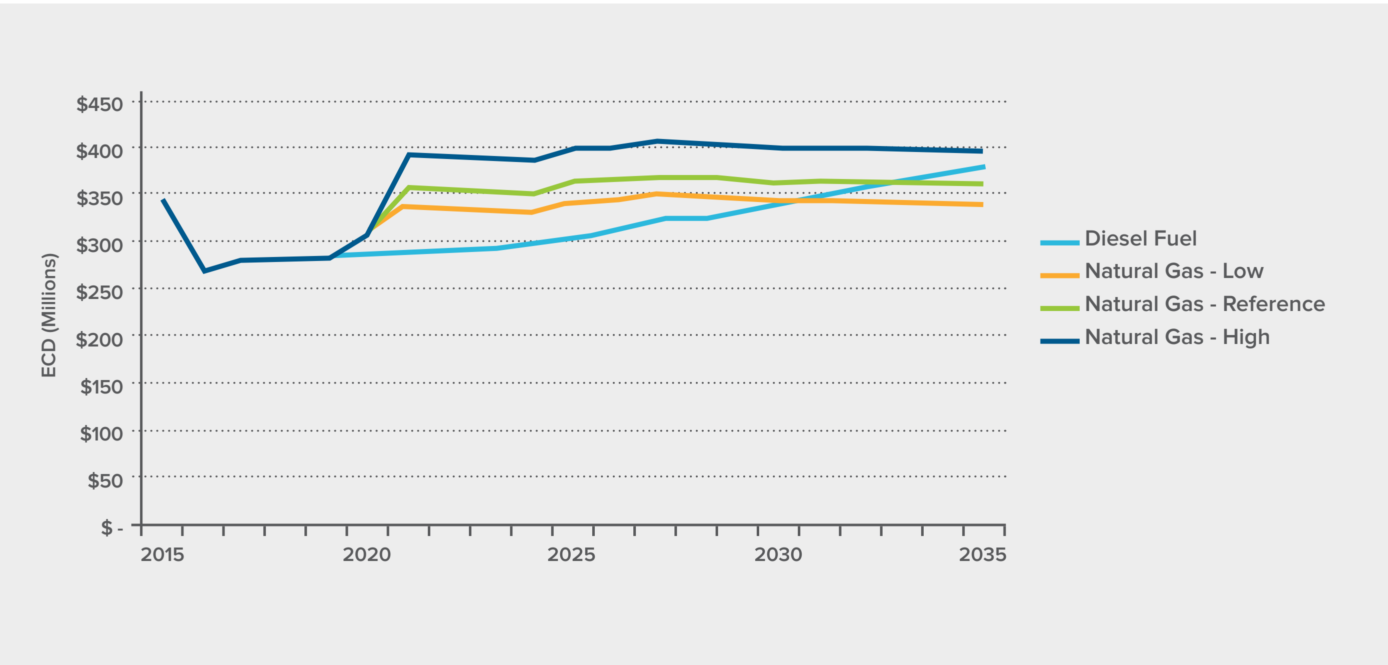
Natural gas could diversify Caribbean energy supply beyond oil, displacing diesel and lowering costs dependent on regional cooperation, land acquisition, and long-term contracts. In addition, natural gas lowers emissions compared with diesel by an estimated 16 per cent (see Appendix M). For natural gas to arrive in Saint Lucia at the appropriate volumes, the following must be established:

- Regional collaboration to attract suppliers of liquefied natural gas (LNG) (requiring at least five years preparation according to IDB).[xi]

[ix] Revenue requirement is calculated as the amount of money LUCELEC must make from customers to recoup costs and earn its targeted return on capital/equity.
[x] Cost estimates came from two separate natural gas suppliers, and generator retrofit costs came from DNV GL.
[xi] Other import approaches exist, including compressed natural gas and pipelines. LNG appears the most cost-effective and likely for imports at the volumes Saint Lucia would need.

**FIGURE 17**

NATURAL GAS COST-EFFECTIVENESS (REVENUE REQUIREMENT)




- Long-term contracts for sourcing natural gas, importing, and operations (can be arranged by a supplier).
- Safe import facilities (requiring sub-zero temperatures and safety precautions) built in Saint Lucia, likely offshore.

For natural gas to provide economic benefit to Saint Lucia, the following must be true:

- All-in gas costs (the full cost to deliver LNG and then regasify it to be usable for power generation) must fall below EC$40/MMBtu, or preferably below EC$32/MMBtu, to outcompete renewable options.
- LUCELEC can sequence retrofits of generators 7, 8, 9, and 10, as a cost of approximately EC$3780/kW (EC$116 million in total).
- Natural gas would need to not correlate to global oil prices in order to reduce fuel price volatility (which has been true recently, but not historically).
- To provide maximum benefit to Saint Lucians, a new fuel supply should reduce the current dependence on diesel fuel. This benefit occurs when LUCELEC has the flexibility to purchase more of an alternative fuel (like natural gas) when diesel is expensive, and vice versa. This process hedges the country's electricity costs and reduces cost volatility.
- However, natural gas suppliers seek to secure long-term contracts at fixed volume, to justify the transportation of relatively low volumes of natural gas. These diverging interests make it difficult to secure a successful contract that benefits Saint Lucia.


## ENERGY STORAGE

Energy storage, in the form of batteries, will play a role in the Saint Lucia electricity system by avoiding reserve capacity and facilitating the integration of variable renewable energy. By reducing diesel consumption, both through firm renewable generation and by increasing the efficiency of continued diesel generation, storage will save money and reduce systemwide costs to operate. The instantaneous response capabilities of storage will increase reliability and allow for minimal upgrades to transmission and distribution infrastructure as the grid adds new renewable assets.

Energy storage can be used to firm or smooth out the energy production from variable renewable resources such as solar PV and wind, and capture and store energy in times when supply of variable renewables exceeds supply. For example, some energy storage resources can help smooth variations in renewable energy output over short time frames (minutes). Other energy storage resources can store greater amounts of energy, smoothing the overall daily profiles of renewable energy output. Utilities globally are also exploring fast-response energy storage for frequency regulation, with a response time in the seconds.

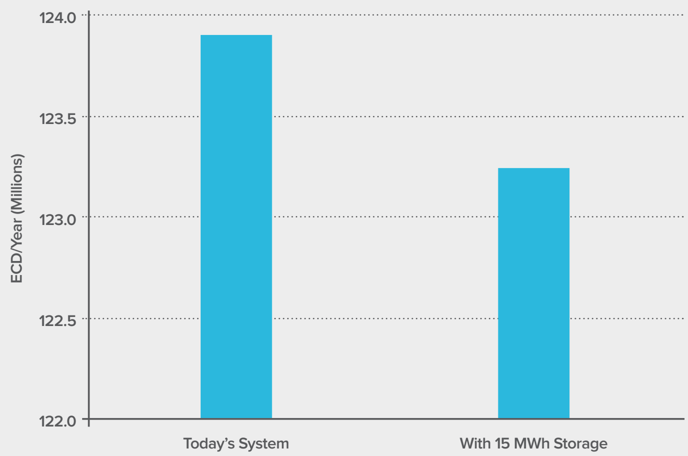
Energy storage can also provide benefits to the utility in the form of fuel savings by avoiding the need to start an additional generator. While average diesel generation efficiency decreases with the addition of renewable resources, it increases with the addition of storage. If a small increase in load is expected for a short period of time, this load could be met with stored energy rather than by starting another generator. While most storage options like batteries are not actually spinning, they can provide the same service as spinning reserves by being immediately available to help cover the load if there is a sudden loss of a generation resource or change in output from a variable renewable resource. Providing this service requires batteries with available energy, prepared to discharge in the event of a generator outage. In contrast, operating storage to smooth variations in renewable energy output or avoid starting diesel generators requires discharging some component of the battery. Overall, the dispatch models revealed that keeping batteries charged (near 100 per cent) and not discharging below 70 per cent offers the greatest value to the grid.

By adding 15 MWh of battery storage to today's system (without new renewable or other generation resources),[xii] LUCELEC could use 110,000 fewer imperial gallons of fuel per year, resulting in fuel savings of EC$660,000 per year (0.5 per cent savings), as shown in Figure 18. The addition of storage allows the diesel generators to be dispatched differently in certain hours, using storage to both meet load and provide operating reserves at different times.

[xii] With the assumptions used for the batteries, 15 MWh provides 45 MW of instantaneous capacity (if discharged at maximum rates).

**FIGURE 18**

FUEL SAVINGS WITH ENERGY STORAGE




### ELECTRIC VEHICLES

If smart charging approaches are utilized, the introduction of electric vehicles in Saint Lucia can benefit both LUCELEC and the electricity grid by providing additional storage resources and increasing total consumption of electricity without increasing the peak load. For example, if 30 per cent of all passenger cars in 2024 were electric vehicles, sales for LUCELEC would grow by an additional 36,541 MWh per year, or an 8 per cent increase over projected sales without EVs. Powering these vehicles adds 8 per cent to total consumption in 2024, and allowing 5 per cent of each vehicle battery to provide services to the grid would provide 50 per cent of the required storage under a high renewable scenario (30 MWh).

In this scenario, EV owners charging their EVs using typical charging patterns would result in an increased peak load of 70 MW, greater than the projected peak load in 2024 of 64 MW. However, using a program to provide incentives for charging at times that are more optimal for the grid brings the peak load to 66 MW and flattens the daily load profile. This smart charging approach allows EVs to provide benefits to LUCELEC, the electricity grid, and the residents of Saint Lucia.

### GRID INTEGRATION OF NEW RESOURCES

LUCELEC maintains the responsibility of ensuring system reliability, both today and in the coming years, which includes providing reliable power even in the event of generation variability, outage, or transmission line failure. After testing future renewable and non-renewable scenarios, the results presented below and in detailed studies completed by DNV GL, including the distribution-level and transmission-level grid integration studies, show that future system reliability and stability can be maintained with frequency support from energy storage systems (e.g., lithium-ion batteries). In addition to energy storage systems, demand response and frequency support from wind turbines can also be used to maintain system stability in the presence of high renewable generation. The two studies completed on the Saint Lucia electricity system are described in more detail below.

### DISTRIBUTION STUDY RESULTS

The distribution study was aimed at identifying any necessary upgrades for both low and high distributed PV scenarios for all study years, since this PV would be interconnected to the distribution system. The load growth forecasts to 2035 were combined with the distributed generation scenarios for each year (see

Appendix K), and DNV GL performed static and quasi-static load flow analyses using software called Synergi Electric. The analysis also included extensive coordination with the energy efficiency and solar resource assessment tasks, as the results and data inputs were dependent on each other.

The analysis examined future years of the IRP study period by extrapolating feeder demand at non-coincident peak and minimum daytime load. This approach is typical for distribution studies and presumes that load conditions outside of peak and daytime minimum will create less pressure on the distribution system. The results are summarised below.

- **Low Distributed PV Scenarios (1.14 MW of distributed solar PV, out of 70 MW total solar in 2035):**
    - Accommodated with no infrastructure improvement (other than interconnection).
    - System benefit is modest, focused on Ciceron and Hospital feeders.
- **High Distributed PV Scenarios (22.9 MW of distributed solar PV, out of 91 MW total solar in 2035):**
    - Accommodated with no infrastructure improvement until 2024.
    - In the 2035 scenarios, it is necessary to contemplate either additional energy storage or co-generation mode on the load tap changers (LTCs).[xiii] Enabling co-generation mode is considerably less expensive, while energy storage can provide additional benefits to the distribution system beyond facilitation of PV interconnections.
    - PV development should be focused on feeders with no voltage or thermal violations in order to reach the level of PV penetration assumed in the scenario.
    - Gros Islet feeder is the only one requiring multiple points of interconnection for potential future distributed generation.

The maps in Figure 19 show the cumulative voltage drop along each feeder for the 2016 and 2035 base case results (these maps form the basis of the distribution-level map modeled in Synergi).

This analysis also includes extensive coordination with the energy efficiency and solar resource assessment tasks, as the results and data inputs were highly overlapping.

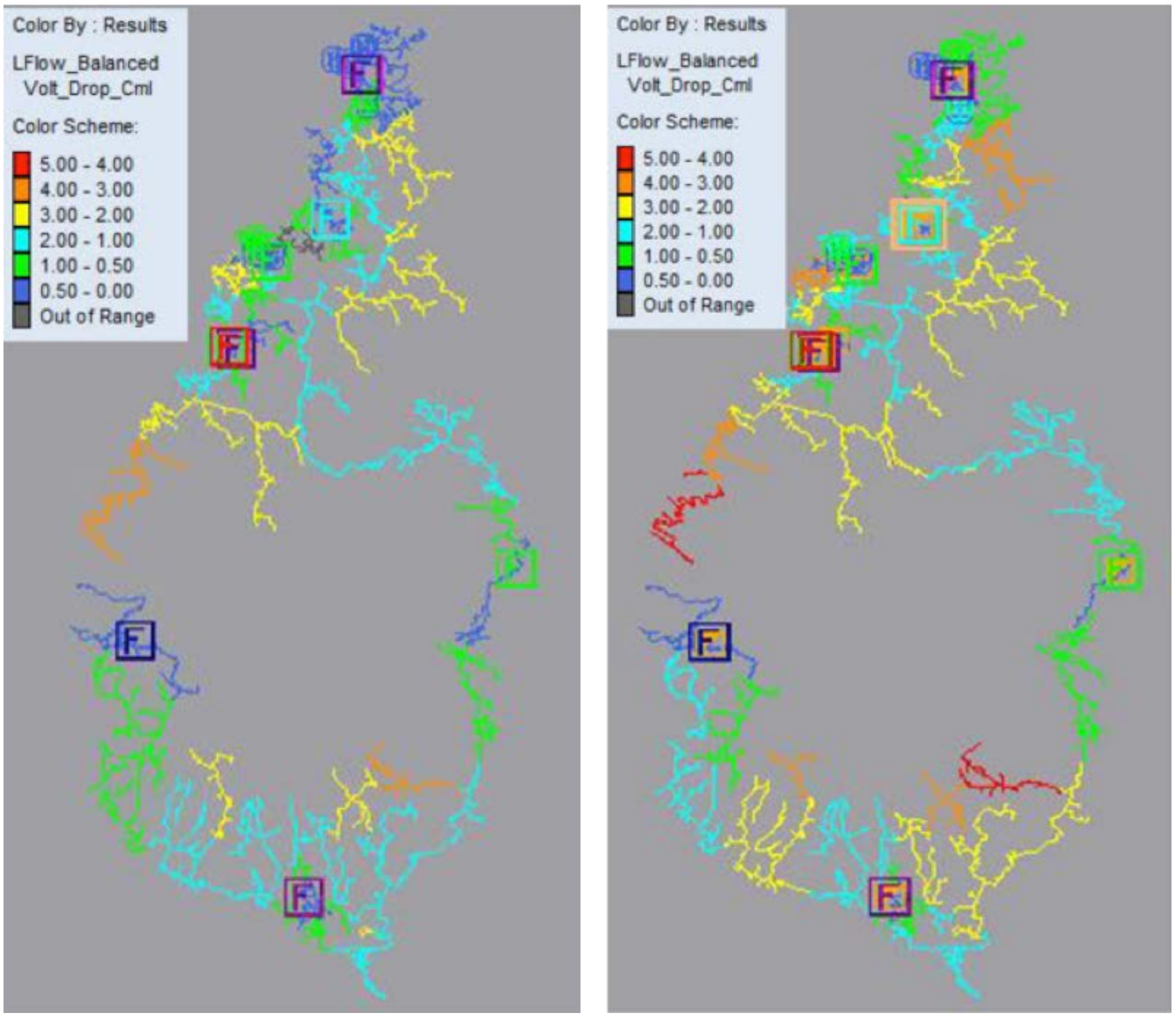
### TRANSMISSION STUDY RESULTS

The objective of the transmission study was to identify any potential thermal and voltage violations on the transmission system due to the additional renewable

[xiii] Load tap changers are a component of a power transformer that allow voltage regulation and/or phase shifting. These would add cost to the distribution transformers.

**FIGURE 19**

DISTRIBUTION MAPS IN 2016 (LEFT) AND 2035 (RIGHT)



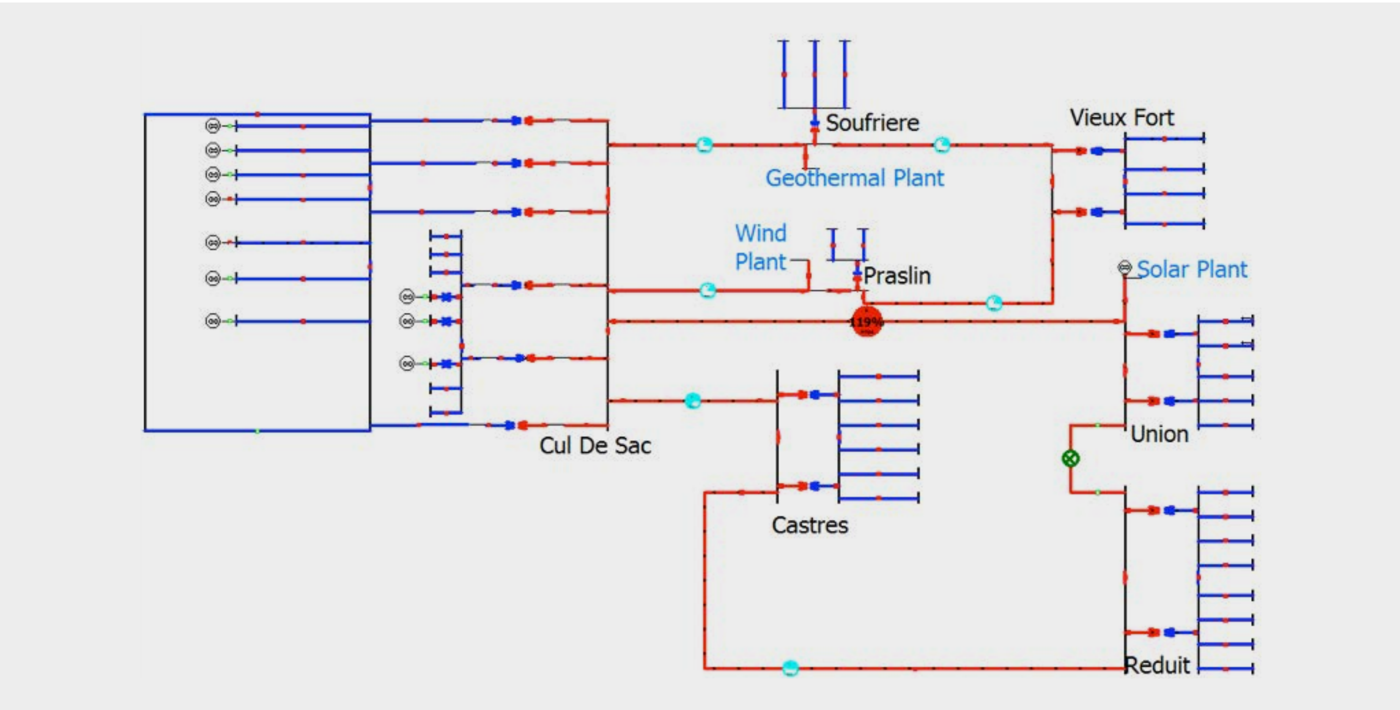

generation, and to identify any system stability problems that may occur. Geothermal, wind, and solar generation resources (as specified from the techno-economic analysis using HOMER) were added to the transmission system model, with distributed generation connected at the distribution substations.

The team performed static and dynamic analyses for each generation portfolio in the transmission study. In the static analysis, the team investigated the effect of renewable generation on transmission line loading, with the aim of identifying any new potential overloads that may occur during a line outage. The analytical team found that thermal overloads can occur if a large amount of PV is interconnected at a single location on the transmission system. Figure 20 shows an example of this with a solar plant connected at Union substation.

The possibility of thermal overloads occurring depends on a number of factors, including load growth, level of distributed generation (which reduces the load on the transmission system), and coincidence of peak load with peak PV output. In the studies

**FIGURE 20**

EXAMPLE OF LINE OVERLOAD BETWEEN CUL DE SAC AND UNION WITH AN OUTAGE OF THE UNION TO REDUIT TRANSMISSION LINE AND A LARGE SOLAR PLANT AT UNION SUBSTATION




performed, thermal overloads occurred only in the 2035 peak load scenarios. Appropriate planning and placement of transmission-connected PV generation as capacity increases can remove the possibility of thermal overloads.

In the dynamic analysis, a single element fault was considered on the system resulting in the outage of the largest online generator. The team monitored the response of the system for 30 seconds following the fault to establish the effect on frequency, voltage, and load shedding. The results showed that existing rules for spinning reserve (see Appendix N) are sufficient to maintain stability up to 2019 in all scenarios, and up to 2024 for the cases with only solar power. Beyond these years, the system requires energy storage or other grid-supporting systems, such as smart inverters or synchronous condensers, to maintain stability, as the available spinning reserves from conventional generators are limited due to displacement by non-dispatchable (i.e., non-controllable) renewable generation resources.

The charts in Figure 21 present the initial results of the dynamic study for the optimal scenario before the addition of energy storage. The fault is initiated after 5 seconds of the analysis, and it results in clear system instability.

The charts in Figure 23 show the same scenario and fault but with the addition of energy storage. In this case, the instability is removed completely and the system recovers quickly following the fault.

**FIGURE 21**
PROJECTED SYSTEM FREQUENCY AFTER FAULT IN 2035 WITHOUT OPERATING STORAGE

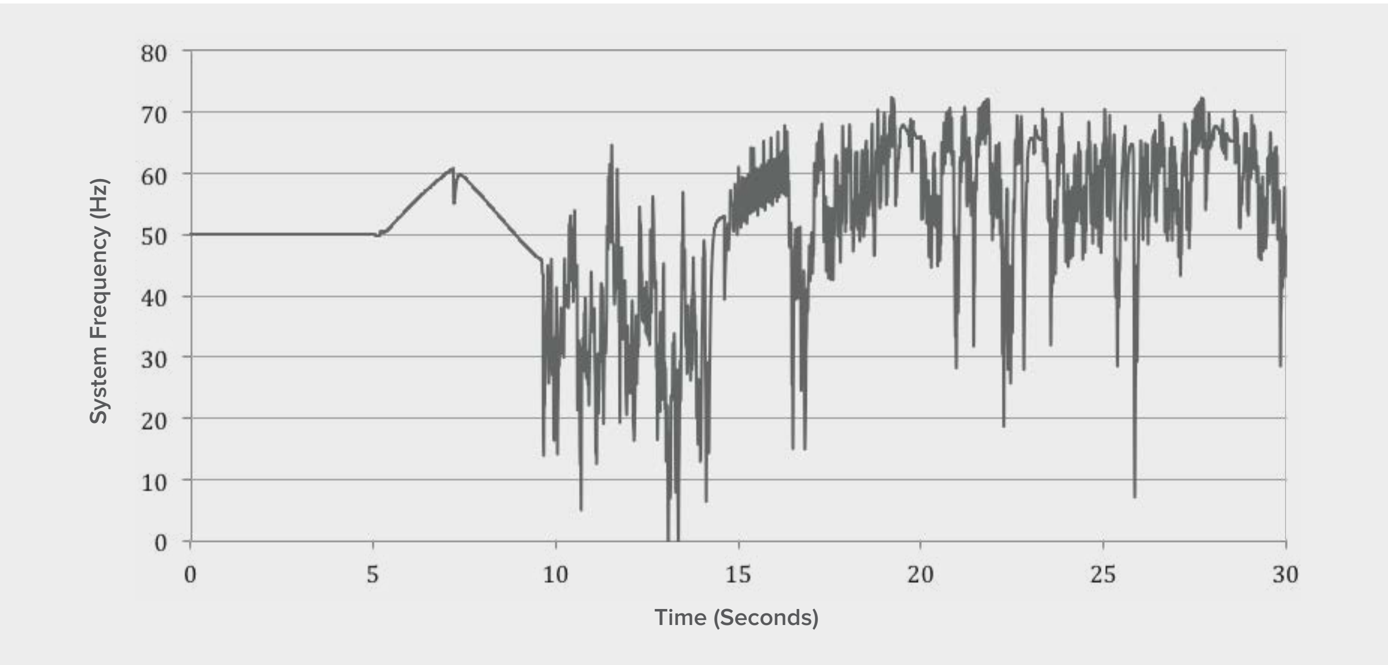



**FIGURE 22**
PROJECTED SYSTEM VOLTAGE AFTER FAULT IN 2035 WITHOUT OPERATING STORAGE

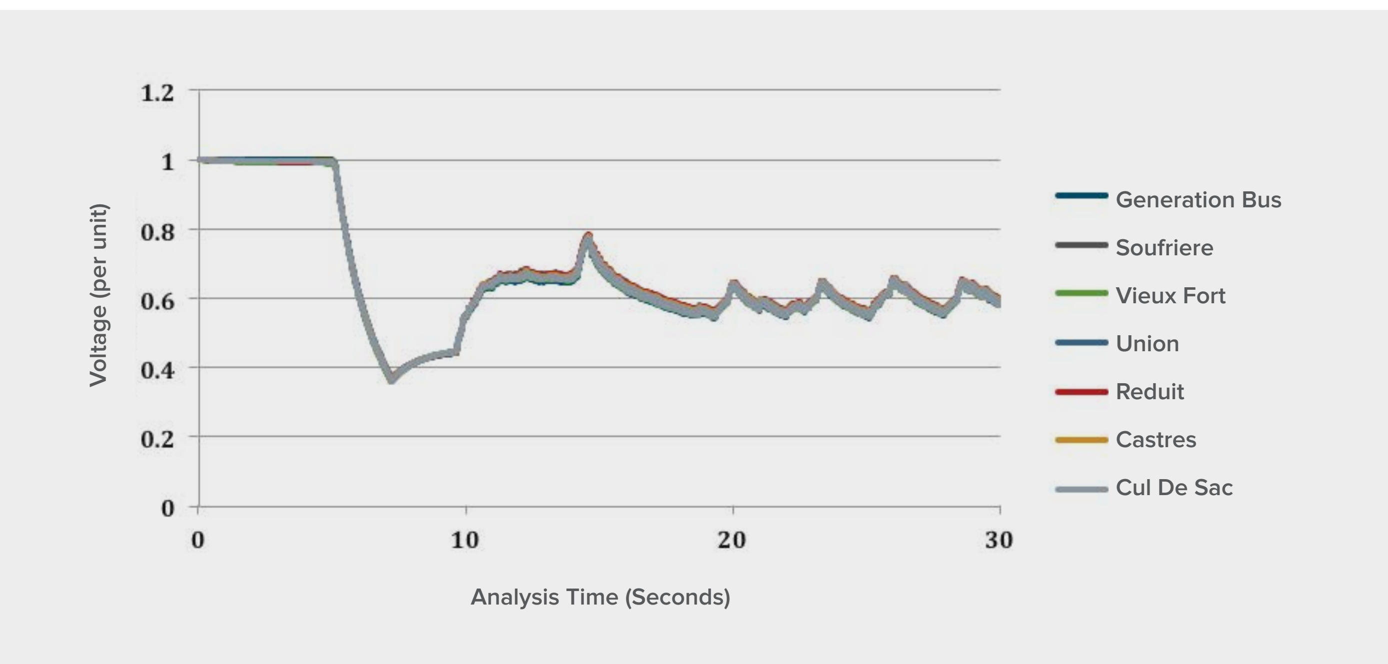


**FIGURE 23**

PROJECTED SYSTEM FREQUENCY AFTER FAULT IN 2035 WITH OPERATING STORAGE

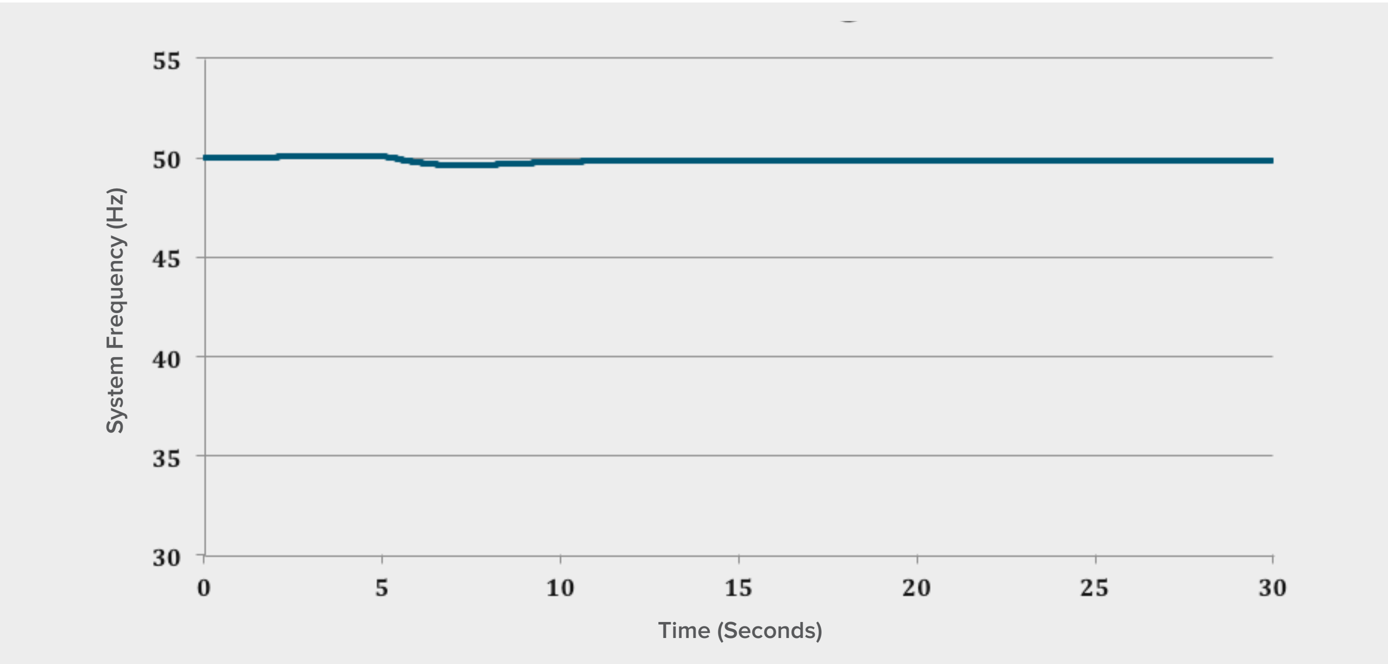
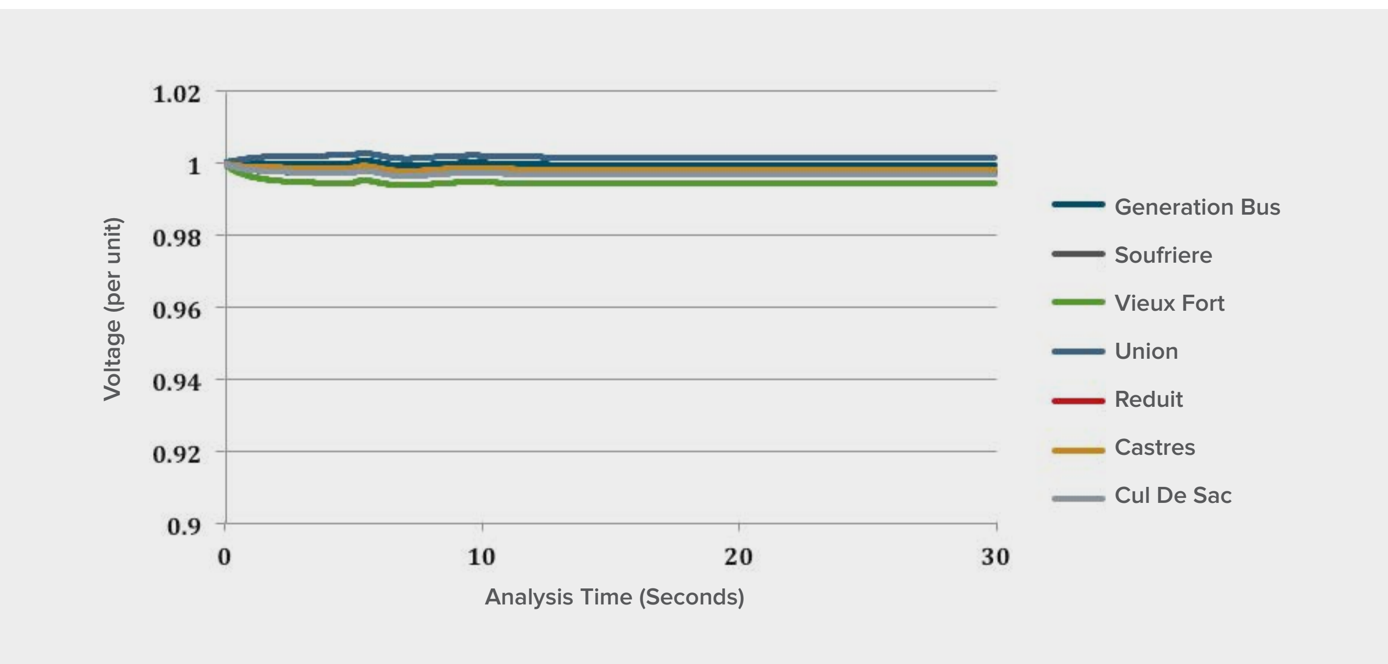



**FIGURE 24**

PROJECTED SYSTEM VOLTAGE AFTER FAULT IN 2035 WITH OPERATING STORAGE



Transmission Study Summary:

- Increasing generation and calculated/planned placement of PV on the distribution system can reduce loading on the transmission system.
- LUCELEC would benefit from developing a siting process for future PV on the transmission system.
    - This would reduce the possibility of overloading, which may necessitate re-conductoring or curtailment.
- There is potential for system instability at higher penetrations of renewable generation as diesel generation is displaced.
- Load shedding schemes were found to be of negligible benefit as load shedding typically coincides with a larger loss of generation due to voltage and frequency ride through settings being exceeded.
- LUCELEC should investigate the coordination of ride-through and load-shedding settings to ensure that generation remains online after load shedding occurs.
- System stability during outages requires that sufficient primary frequency response is available. In earlier years (up to 2019 with wind and geothermal power included, and up to 2024 with just solar power), this is possible using spinning reserve from online generators. In later years, system reliability and stability can be maintained with frequency support from energy storage systems.
- Demand response and frequency support from wind turbines can also be used to maintain system stability in the presence of high renewable generation output. Smart inverters on the solar generation can also support grid stability by curtailing solar output when needed.

In summary, the grid can remain reliable under a variety of scenarios; however, adding renewable energy requires electricity storage. The levels of electricity storage found to be economical for the system provided sufficient instantaneous reserve capacity to ride-through generator outages in the coming 20 years (with issues emerging with 2035 load and generation conditions).

## ECONOMIC

When compared to today's electricity system, Saint Lucia's future electricity system can provide power at lower total costs—benefitting residential customers, small businesses, hotels, and other consumers of electricity. Ultimately, lower and stable electricity prices will spur job creation and high skill employment, including jobs operating new energy resources. Every week Saint Lucia waits to pursue energy efficiency and solar defers potential savings of approximately EC$270,000. Improving the electricity system now will gradually improve the economy, as immediate customer benefits will persist over the coming years.

To determine the economically optimal amount of resources to add to the Saint Lucian electricity system, the team assessed different scenarios, each optimised to be least cost given the mix of resources selected. Total new capital investments vary by scenario, with the highest being EC$665 million (to retrofit generators and construct receiving terminals for natural gas), with operating cost reductions of 22 percent. Renewable scenarios offer reduced operating costs (up to 19 per cent less than the diesel-fuel-only reference case), with required capital investments between EC$180 million and EC$520 million.

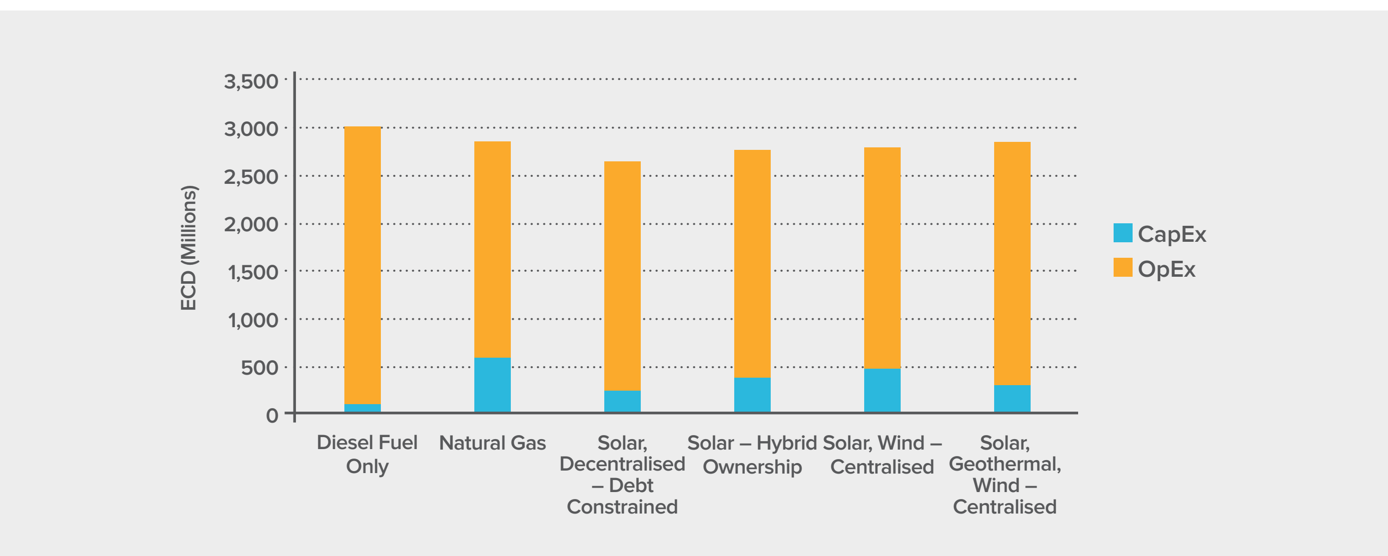
Reducing operational expenditures (which greatly outweigh capital expenditures, as shown in Figure 25) through saved diesel fuel will provide stabilisation against fluctuating diesel prices over the coming 20 years.

In the coming 20 years, Saint Lucia will spend between EC$3.6 and $4.7 billion to operate the electricity system (between EC$2.9 and $2.3 billion discounted). Capital expenditures (discounted to today) in the reference case are EC$105 million (to overhaul and expand existing diesel).

When energy resources are considered independent of system interactions, one metric is the equivalent cost of diesel to make them compete at parity. In this case, many options are more cost-effective than diesel generation. The current (2016) diesel LCOE is approximately EC$0.40/kWh.

**FIGURE 25**

DISCOUNTED CAPITAL AND OPERATING COSTS BY SCENARIO



**VARIOUS RESOURCES' COST COMPETITIVENESS WITH DIESEL**

Firm Resources:

Natural gas is cost competitive with diesel (presuming the availability of supply) at today's oil prices (above EC$100 per barrel).

Geothermal PPA (currently modeled between EC$0.49/kWh and $0.41/kWh) becomes cost competitive with diesel if the price of oil rises to EC$194 (US$72) per barrel and remains at or above that level.

Solar + storage becomes cost competitive with diesel if the price of oil rises to EC$135 (US$50) per barrel.

Variable Resources:

Energy efficiency is cost competitive with diesel at almost all feasible oil prices (above EC$13.5 [US$5] per barrel).

Solar is cost competitive at today's oil prices (above EC$73 [US$27] per barrel) until storage becomes required (see above).

Wind PPA (currently proposed at EC$0.49/kWh) becomes cost competitive if the price of oil rises to EC$203 (US$75) per barrel and remains at or above that level. This presumes minimal system costs for integration (to be investigated further).

LUCELEC-owned wind becomes cost competitive at or above EC$124 (US$46) per barrel of oil.

Energy efficiency is the cheapest resource available, costing approximately EC$0.14 to $0.19 per kWh (including program operation costs), and is largely untapped in Saint Lucia.

Despite recent decreases in the price of diesel, renewables are currently economically attractive. The LCOE for solar for Saint Lucia is between EC$0.19/kWh and $0.24/kWh based on recent bids. Wind (12 MW) and geothermal (30 MW) PPAs as currently outlined (EC$0.49/kWh, take-or-pay contracts) are more expensive than diesel generation, but could become viable and beneficial under the right conditions, such as higher oil prices, increased load growth, and/or lower PPA costs.

LCOE as a metric does not fully capture differences in variable resources that are limited by different factors such as incident solar or prevailing wind. Looking only at the economic feasibility due to the dropping costs of the individual technologies omits the whole-system perspective. It is more important to look at the whole operating cost and technologies in combination.

When assessed in terms of total operating cost, two particular scenarios—both mixes of solar, diesel, and storage; one with high levels of distributed generation and one with low levels of distributed generation—offer low total cost to operate the system. A comparison of total cost to operate across the six scenarios is shown in Figure 26.

Revenue requirement, an alternative metric to total operating cost, includes a component of return on rate base (or the total value of the utility's investment in facilities). This metric incorporates not only the cost to generate electricity but also the necessity of recouping utility investments. Figure 27 shows a comparison of revenue requirement across the six scenarios.

Opportunities, as described in the section above, include energy efficiency, renewable energy, and natural gas. Although many scenarios offer reduced costs to generate, rate reduction will be relatively small: less than 10 per cent reduction versus business as usual, or 25 per cent less than today's electricity

**FIGURE 26**

TOTAL COST TO OPERATE,[xv] 2015 TO 2035

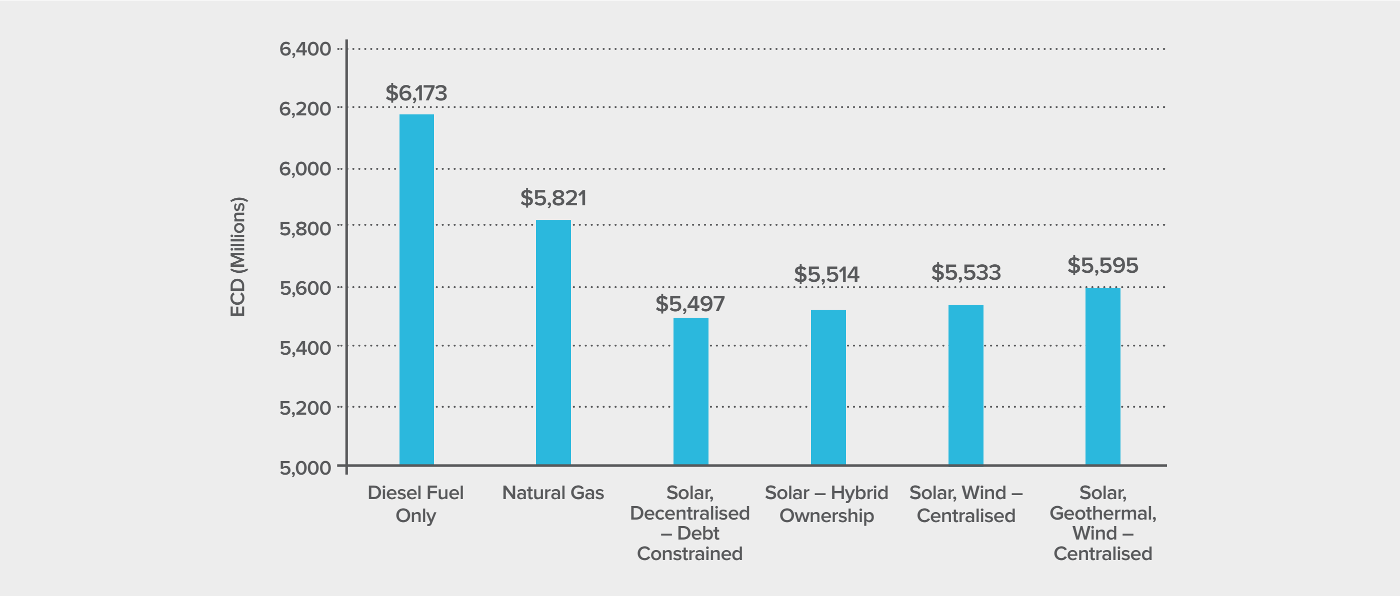
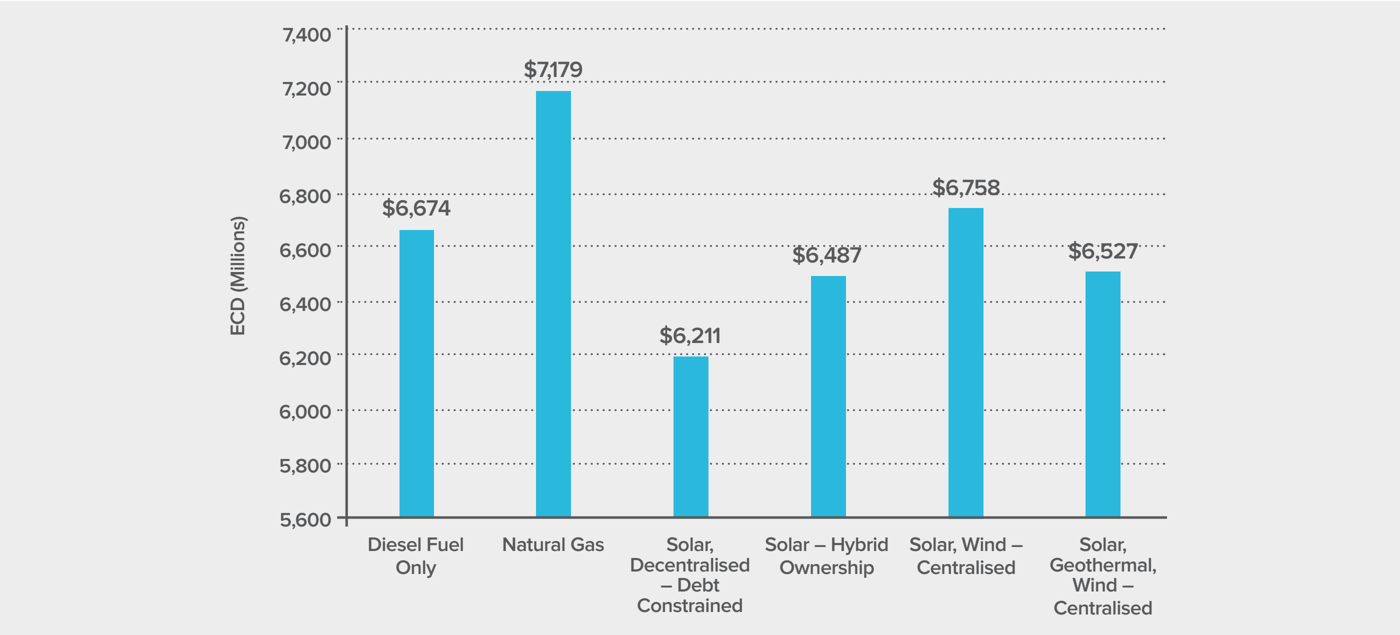



**FIGURE 27**

REVENUE REQUIREMENT, 2015 TO 2035




[xv] This metric includes all operating costs, as well as debt service and equity payments for new investments.

price with expected inflation. Any rate reduction requires a long lead time to appear (at least five years), due to debt service for new renewable generation and continued payments on existing assets. Rate reduction is maximised in the natural gas and optimal renewable energy scenarios, as shown in Table 2.

Future rates were projected using current rate regulations.[xvi] For a discussion of alternative approaches, see the Regulatory section below.

In the coming 20 years and under all assessed scenarios, the continued primary driver of Saint Lucian electricity costs will be the price of diesel (driven by the world market for oil). Renewable energy provides a valuable hedge, damping any fluctuations in the price of diesel and stabilizing the rate that Saint Lucians pay for electricity. This is demonstrated in Table 2, showing the projected domestic and commercial rates for the optimal scenario.

When assessed in terms of revenue requirements, all scenarios with high levels of distributed generation or independent power producers (IPPs) appear beneficial. This is because any distributed generation reduces the total utility-owned investments that must

**TABLE 2**

RATE IMPACT BY SCENARIO

| SCENARIO | PROJECTED ELECTRICITY RATE IN 2035 (EC$/Wh) | AVERAGE RATE OVER 20 YEARS (EC$/kWh) |
|---|---|---|
| 1. Diesel Fuel Only | $0.89 | $0.80 |
| 2. Solar High DG | $0.91 | $0.82 |
| 3. Solar Mid DG | $0.84 | $0.79 |
| 7. Solar Wind Low DG | $0.80 | $0.77 |
| 13. Solar Geo Wind Low DG | $0.83 | $0.78 |
| 14. Thermal IPP | $0.82 | $0.75 |

[xvi] Rates in Saint Lucia are volumetric (charged per kWh to all customers) and comprised of three parts (a basic rate, a fuel pass through, and a fuel adjustment). The basic rate adjusts based on a band of allowable return for LUCELEC, and changes occur after an annual submission to Ministry of Finance.

be recouped through the rate mechanism. However, any customers participating in distributed generation programs will reduce the revenue captured by LUCELEC, and thereby lead to higher rates. The average customer rate over 20 years is shown in Figure 29, comparing scenarios with utility-scale solar and varying amounts of distributed solar, with the more distributed generation raising rates versus more utility ownership.

Distributed generation offers compelling benefits to Saint Lucia. First, this generation approach includes citizens in the energy transition. Second, allowing customers to use their roofs to host solar avoids potentially costly land acquisition by LUCELEC or private developers. Lastly, distributed generation can lessen grid congestion on specific feeders, possibly delaying upgrade costs.

Currently, LUCELEC-owned solar is cheaper to install than distributed solar, due to differences in cost of capital and differing scale (by installing larger projects, LUCELEC would achieve economies of scale). Weighted average cost of capital presumed for LUCELEC is 5 per cent, and most suppliers providing financing for residential or commercial solar systems bring much higher cost of capital.

Distributed generation could impact LUCELEC's profitability by decreasing its revenue. Customers would remain connected to the grid but self-generate a portion of their electricity, thereby reducing LUCELEC's revenue. Currently, this approach has been piloted and tested by LUCELEC, with caps on the amount of generation each customer can connect. The IRP finds that under current assumptions, these revenue decreases are immaterial (in other words, LUCELEC can remain profitable—see Appendix J) unless fuel prices or customer defection (due to cheap solar and storage) shift materially. If many more customers defect from the grid, caps can help ensure the safety and stability of the grid.

Based on the experiences of other islands, distributed generation should be carefully managed, with caps put in place to ensure a careful and managed transition, which will ensure equitable sharing of the benefits of renewable energy. Further study is needed to determine the appropriate cap on renewable energy and the right tariff design to compensate both customers and LUCELEC for the operation of a reliable grid. The NURC should be deeply involved to weigh the costs and benefits and to ultimately determine the right approach and cap (which should be revisited periodically). LUCELEC should manage interconnection, acceptance, and technical testing.

With current diesel prices (relatively low) and solar and storage costs (declining), a portfolio of solar, wind, diesel, and storage (including low levels of distributed generation) appears beneficial from a cost-to-operate perspective as well as a rate-impact perspective. Eventually geothermal, solar, and storage might be able to lead Saint Lucia toward higher penetration levels of renewable energy depending on the cost of storage (ice storage, EVs, and demand flexibility can help).

Near-term action improves the economics of an energy transition. Cheap worldwide oil (EC$122 or US$45 per barrel) has made diesel prices drop (from EC$14.5 to $8.2 per imperial gallon), putting wind and geothermal (at 12 MW and 30 MW respectively) out of the money. However, if diesel prices increase to EC$12.30 per imperial gallon or above, these projects will become cost-effective. Meanwhile, solar and energy efficiency are cost-effective today and can be installed relatively quickly compared to other energy investments, allowing for close and timely matching between demand growth, efficiency incentives, and generation expansion.

FIGURE 28

HISTORICAL AND PROJECTED DIESEL PRICE AND RATE IMPACT

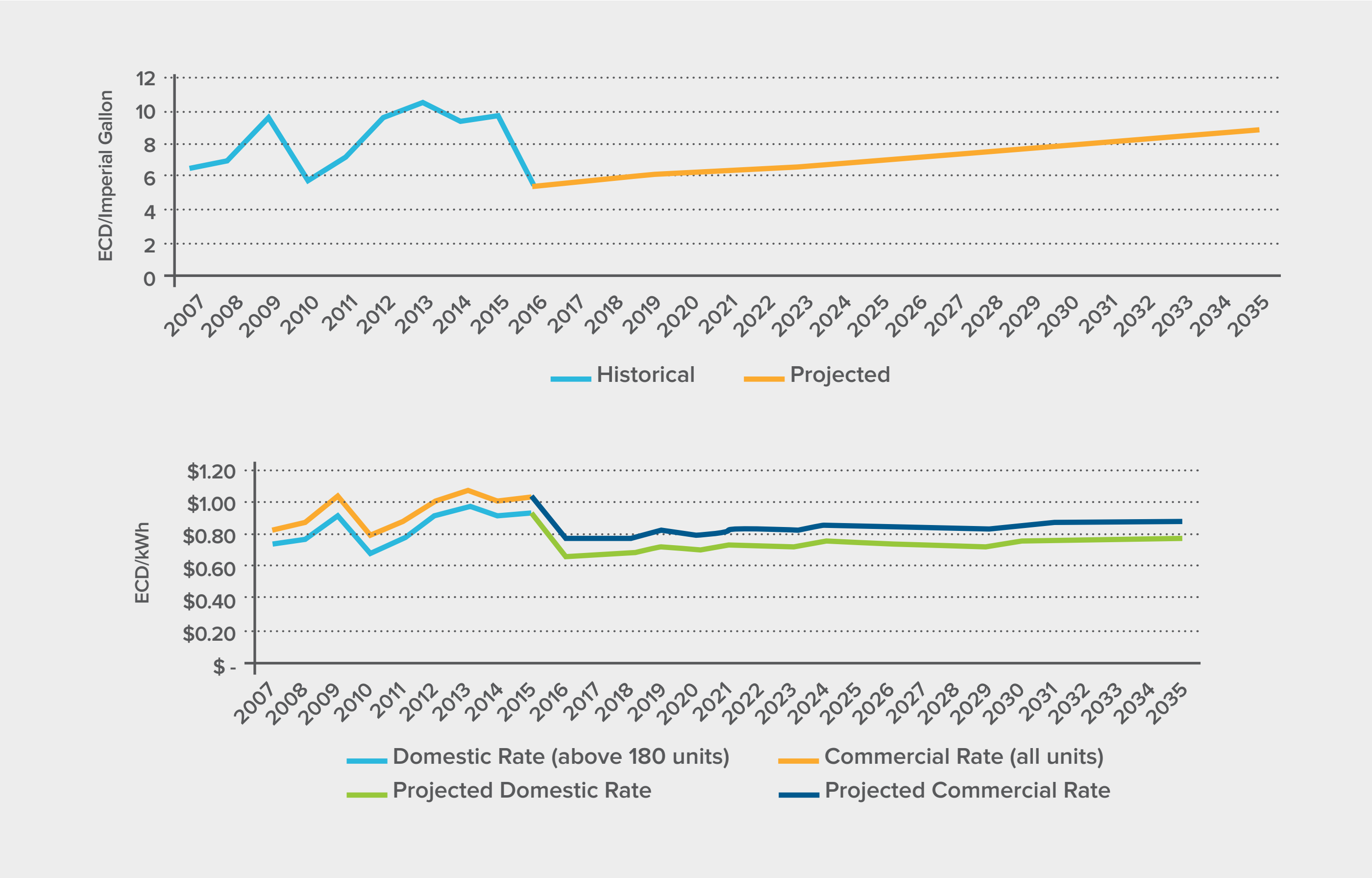
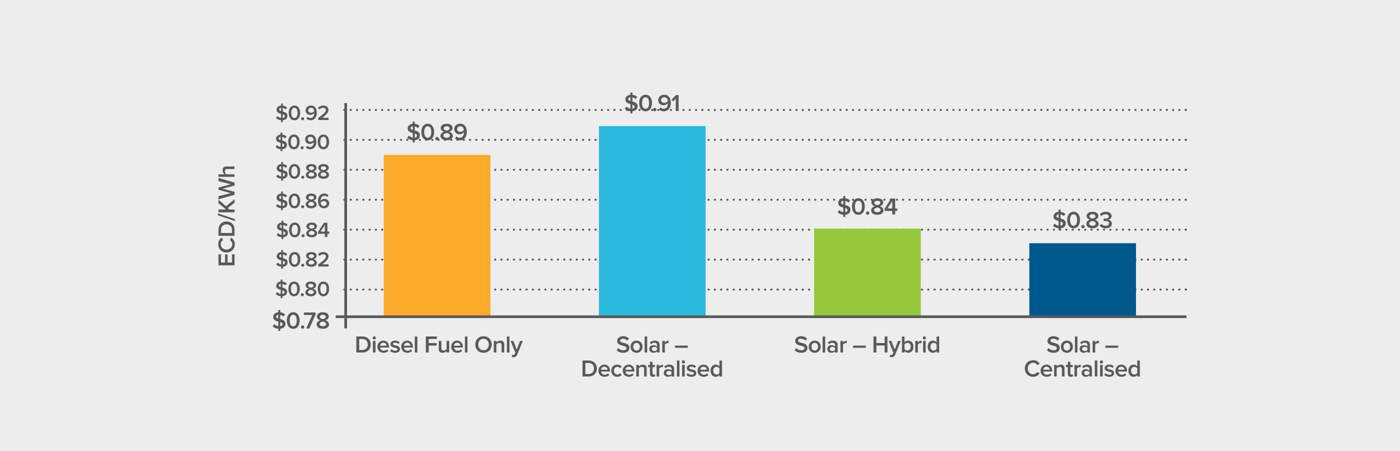



FIGURE 29

AVERAGE CUSTOMER RATE OVER 20 YEARS



## REGULATION

The current electric utility and regulatory framework must change to take advantage of the opportunities detailed in this IRP. Several challenges related to inadequate regulation currently exist. First, LUCELEC lacks a mechanism to recover costs from customers for utility-owned renewables. Second, the system has no governing policy for distributed generation. Lastly, LUCELEC is not compensated or incentivised for pursuing customer-sited energy efficiency.

Fortunately, the government recognises a need for changes to the electric utility regulatory framework and is engaging deeply with LUCELEC in this process, tackling questions regarding operations of the grid, economic viability for ratepayers, and utility financial stability.

In 2010, Saint Lucia began a process to revise the electricity regulatory framework (last updated in 2006), including the concessionary agreement, in line with national objectives to increase the use of renewable energy. In early 2016, a new independent National Utilities Regulatory Commission (NURC) was established. It will eventually govern all transition initiatives.

Therefore, Saint Lucia, led by the NURC, needs to accomplish three objectives:

1. Modify existing rate regulations to prevent rate shock as renewable PPAs come onto the system
2. Determine equitable levels of customer participation in solar through a study to determine optimal caps and pricing for distributed generation
3. Enable utility-sponsored energy efficiency, by providing an incentive to LUCELEC

### PREVENTING RATE SHOCK

Three general regulatory frameworks govern modern utilities: rate of return, price cap, and revenue cap. Most utilities operate under a hybrid of these three approaches. LUCELEC operates using the allowable rate-of-return approach. In the case where profits are in excess of the regulated rate of return, the excess profits are shared. LUCELEC keeps 50 per cent and the rest reduces the rates industrial and hotel customers pay the following year (called "shared earnings"). The Minister responsible for energy policy (and in the future – the NURC) may also, by order, apply the decrease in the rates to consumers or groups of consumers in need of special protection.

When independent power producers are introduced into the system, the contractual power purchase agreement means that LUCELEC buys energy at an agreed-upon price for a certain length of time (~20 years). LUCELEC then distributes this energy to customers. The cost of an IPP-generated kWh to consumers is the PPA price plus transmission and distribution costs plus rate of return. However, for renewable energy IPPs, there is no fuel consumption. According to the current tariff rules, customers pay only for the non-fuel portion of the tariff, even though it costs LUCELEC much more than that to deliver to the customer. In other words, LUCELEC makes a loss, which is dependent on the energy generation capacity of the IPP. The loss may occur for one year, and in some cases for two years. When the rate of return falls below the allowable band, the basic non-fuel rate adjusts upwards quite steeply. This is called rate shock.

This is an important consequence to be aware of. If the government were to facilitate IPPs, for example by providing tax exemptions for renewable energy and energy efficiency projects, the scale and PPA price should be proactively managed in order to control sudden rate hikes.

The advantage of rate-of-return legislation is that it facilitates innovative investments. This means that if LUCELEC wants to invest in a wind farm, for example, profit might fall below the allowable band in the first year (due to increased costs). When this happens, the base non-fuel rate adjusts upwards to a level that will allow the rate of return to re-enter the allowable rate-of-return band. The downside is that rates rise in all scenarios, even the diesel-fuel-only scenario. The objective of containing costs is therefore not achieved under this rate regime, even though many scenarios offer a lower cost of operation. Also, utilities globally have historically not made investments in alternative technologies, even with a rate-of-return regulation. What's more, this does not incentivise improvements in generator fuel efficiency because full fuel cost are passed through to the customers.

Price-cap regulation has the advantage over revenue-cap regulation in that it protects the consumer against uncontrolled rate increases. Rate shock does still occur with price-cap regulation, although the extent of the shock is less. The regulations allow for tariff reviews every five years. This is where the long-term plan adds tremendous value. Once the regulator understands that an investment is in the best interest of the consumer, the regulator can approve the investment by adjusting the price cap to allow appropriate and timely recovery of the investment while protecting consumers.

The risk with price-cap regulation to the utility is that the investments in new generation assets may not be recovered in a timely fashion. As with rate-of-return regulation, the rates increase if revenues are not sufficient to meet costs. The capital expenditure profile of renewable energy investments differs from that of diesel generation assets in that renewable investments are capital intensive at the onset, whereas diesel assets have significant operation and maintenance costs. The utility needs to be assured of revenue recovery for its investments.

Developing the appropriate charge to recover the costs of renewable energy investments should be the first focus of the NURC. This charge should reflect the amortised capital costs of installing new renewable energy. Under the current paradigm, if LUCELEC is not able to participate in the renewable transition, rates would increase as LUCELEC's revenue declines. LUCELEC's revenue requirement across the six scenarios is shown in Figure 30.

Prior analysis (from Meister Consultants Group) projected rates based on current market conditions and the fair rate of return for a customer owning renewable energy. However, as diesel prices fluctuate, and the avoided cost of generation for LUCELEC diverges from the set rate paid to customers with distributed generation, potential equity issues arise. These can be overcome by tying prices more closely to the long-term marginal cost of generating power with diesel while factoring in the cost to run the reliable grid.

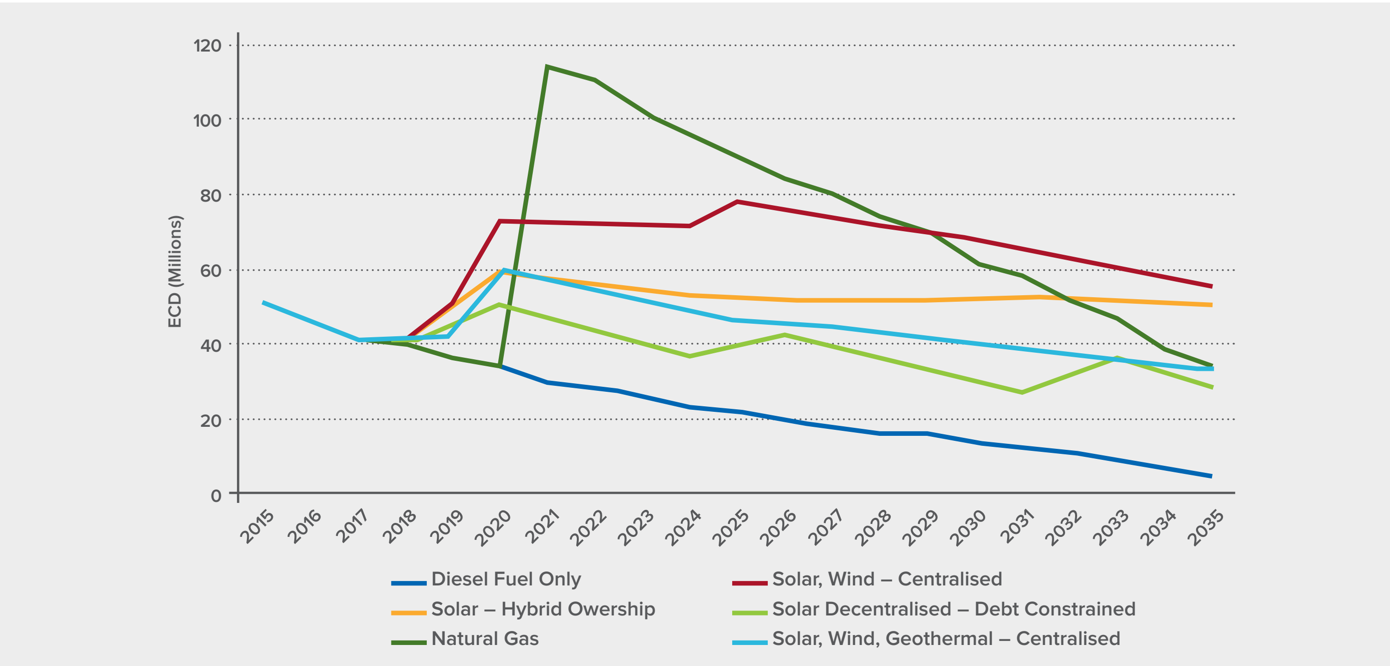
Determining equitable levels of customer participation While enabling customer-sited renewables (with reasonable caps) helps meet a variety of Saint Lucia's goals, it has the potential to disproportionately benefit wealthier individuals, restrict profit, and impose costs on non-distributed generation users. Therefore, a system that allows distributed generation and has both user caps and system-wide caps is recommended, and users should be paid a rate between the avoided cost of power and the retail rate. Further discussions with the NURC on that rate are crucial as customers seek clarity on this important topic.

### ENABLING UTILITY-SPONSORED ENERGY EFFICIENCY

As discussed previously, the utility has no incentive for encouraging energy efficiency at the consumer level. However, energy efficiency offers a significant opportunity to reduce system costs. While this reduces revenue, once the right financial structure is in place, the utility's profit can remain the same or even increase. An alternative rate regime, revenue cap,

**FIGURE 30**

REVENUE REQUIREMENT BY SCENARIO




guarantees the annual revenue of the utility regardless of sales. In other words, revenues are decoupled from sales. Furthermore, there are alternative rate designs that price the cost of electricity differently and send clear signals to the market.

## TARIFF REFORM

The optimal case has been chosen to minimise costs while ensuring a highly reliable electricity system. In order to capture those benefits without disruptive changes in tariffs, it is important to adjust the regulatory approach to setting tariffs.

For example, under the current tariff scheme, costs are passed on to consumers retroactively in one-year adjustments. If extraordinarily high costs are incurred in a given year, the utility has a shortfall in revenues. In the next year, the rate is adjusted and consumers then see a large increase in rates (see Figure 31). In order to avoid those gyrations, it is essential to smooth the process for passing costs on to the consumer.

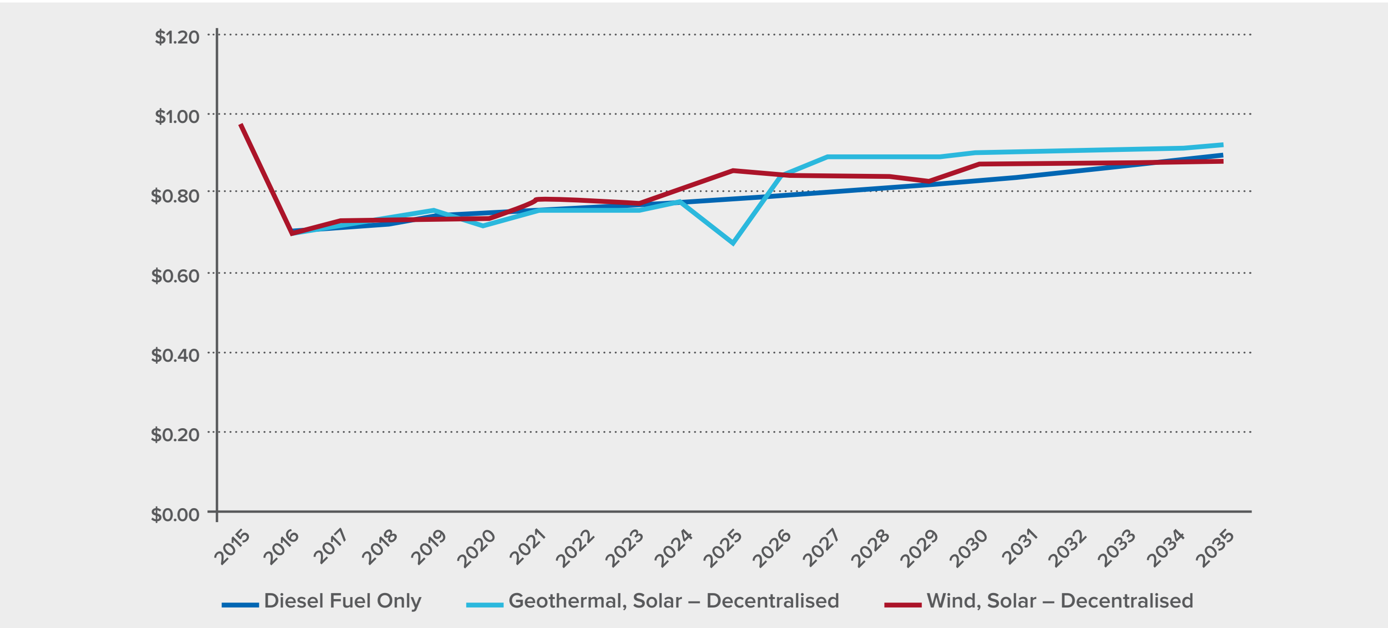
Options for avoiding rate shock include categorizing PPA expenditures as fuel, preparing a rate case in advance of the geothermal coming online, and modifying the core rate regulation to a new modality (either price cap or decoupling).

## RATE MAKING

Rate making aims to ensure that a utility recovers costs plus earns a fair rate of return, while customers receive the best value. A utility's cost can be broken down into fixed and variable costs. To determine the correct rate, the utility must first determine its total cost, including the fair rate of return on prudent capital. This forms the "revenue requirement." The utility can then set rates by allocating a share of required revenue to each customer class and determining the structure of the rates. Ideally the objectives of rate making align with the objectives of the IRP—reliability, cost containment,

**FIGURE 31**

RATE SHOCK FROM GEOTHERMAL PPA




and energy independence/achieving renewable energy targets.

Once the revenue requirement is calculated and the vision for the future energy sector is established, the utility and regulator can work together to determine the best way to recoup costs—in other words, determine the rate structure (how this would appear on customer's bills). There are many options and combinations available to achieve cost recovery.

Recovering more from fixed charges enhances revenue stability but weakens price signals that will help reduce consumption and reduces affordability for low-income households. Recovering more from variable charges reduces revenue stability but strengthens the price signals and is more affordable for low-income customers.

One way to recover the cost of generating electricity from renewables is through a renewable energy charge. It can be implemented in many different ways, including a charge covering the total cost distributed proportionately based on consumption, or an optional charge, separate from tariffs, where customers finance utility investment in renewables.

Time-of-use rates and demand charges are often explored by utilities. LUCELEC has been rolling out smart metres with the capabilities required for measuring and recording the relevant data to be able to implement these rate design options. The analytical team recommends that the NURC fully explore these options.

While the operations of today are not adequate and uncertainty exists in how to handle distributed generation, regulatory certainty may be emerging through the NURC. As the independent regulator in authority with a mandate for more renewable energy, the NURC focuses on and prioritizes the citizens of Saint Lucia.

## BENEFITS, CHALLENGES, AND RISKS

Pursuing a careful energy transition brings many benefits, including decreased generation costs and customer rates and increased reliability. The team found the following five benefits would result from this transition:

1. **Costs to generate electricity will likely decrease over time.** Both energy efficiency and solar are cheaper resources than diesel. The system must reach approximately 25 per cent renewable penetration and 10 per cent avoided load before efficiency and renewable energy materially decrease diesel generator efficiency. An avoided new diesel generator in 2023 (12.4 MW) improves economics for additional renewables. In a volatile and high-fuel-cost future, total costs increase 38 per cent over 20 years when operating diesel, versus 28 per cent for a renewable mix.

2. **LUCELEC will remain financially viable and a stable employer.** Fixed costs for operating the system can be recouped through ongoing electricity sales, supported by regulatory changes, specifically the inclusion of a demand charge. Variable costs (mostly fuel) will decrease by 30–50 per cent (versus business as usual) and allow for rate reduction without reduced profit. While debt will pose a primary challenge, it can be overcome through the Caribbean Development Bank (CDB) and other opportunities.

3. **Customer rates will decrease while maintaining equity among customers.** Average tariffs will decrease by 10 per cent in 10 years under the current regulatory regime. Also, customers with distributed generation will not cause undue burden on the system.

4. **The electricity system will remain highly reliable.** Current grid integration results show that storage can mitigate many of the issues with higher renewable penetration at reasonable cost (incorporated into the economic results above).

5. **The renewable penetration target** (35 per cent, expressed in energy) **will be met by 2022** (two years later than the goal of 2020 expressed in current policy documents). A pathway including geothermal reduces the economically optimal renewables installed before 2024 (when geothermal comes online), producing a renewable energy penetration of 15 per cent in 2022, and an increased renewable energy share of 72 per cent by 2024.

### SENSITIVITY ANALYSIS

Numerous factors can influence the future economic implications of Saint Lucia's energy transition. The results presented in this IRP document reflect mutually agreed upon assumptions and inputs. As some of these assumptions change, so will the results, making certain investments un-economic or unnecessary. To assess these potential futures, the analytical team analyzed sensitivities to test factors both within and outside the control of Saint Lucia stakeholders.

Uncontrollable factors:

- Price of diesel fuel—Fuel may remain low, return to higher prices, or exhibit volatility (as has historically been the case).

- Price of alternatives—For example natural gas supply contracts or solar and storage costs, including land, procurement, and insurance, may change.

- Load growth—Saint Lucia's electricity demand (annual consumption and peak) may increase or decrease, influenced primarily by GDP growth.

Controllable factors:

- Operating reserve margin—The amount of instantaneous reserve capacity required comes from generators that are running below 100 per cent of their rated output and can ramp up as well as from energy storage devices that are charged and available to discharge.
- Energy efficiency program implementation—Deploying a program to encourage cost-effective energy efficiency across different customer groups in Saint Lucia requires funding, staff, and appropriate regulations. If energy efficiency measures are not adopted, electricity loads will remain higher than projected.

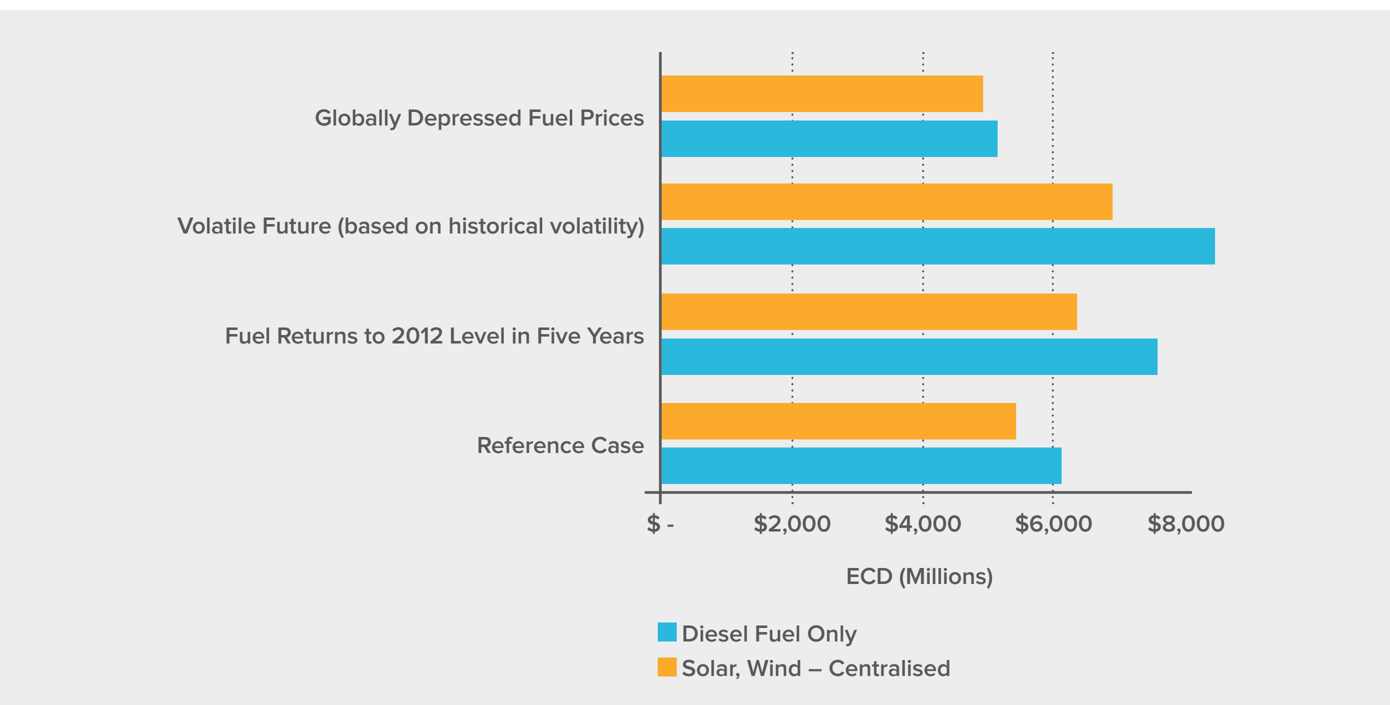
The five sensitivities that were tested included the price of diesel fuel, operating reserve margin, load forecast, energy efficiency program implementation, and capital and operating costs for renewable energy and energy efficiency investments.

### 1. *Price of diesel fuel:*

An examination of alternate diesel fuel price forecasts shows that scenarios including renewable resources result in lower and more stable costs **across all different fuel price forecasts**.

In all tested fuel scenarios (shown in Figure 33), a renewable transition lowers overall costs to operate the electricity system, including debt payments for new investments (shown in Figure 1). In the volatile and high-fuel future (derived from historical fuel volatility), total costs increase 38 per cent when operating diesel versus 28 per cent for the cost-optimal renewable mix (see Figure 32 and Appendix C for fuel price inputs). In a future of globally depressed fuel prices (with oil

**FIGURE 32**
DIESEL PRICE SENSITIVITY FOR SELECT SCENARIOS



staying close to US$50 per barrel), a renewable mix provides 5 per cent lower costs to operate the electricity system. These results show renewable generation serving as a partial hedge against high diesel prices, allowing for a more stable and low-cost electricity system for Saint Lucia.

### 2. *Operating reserve margin:*

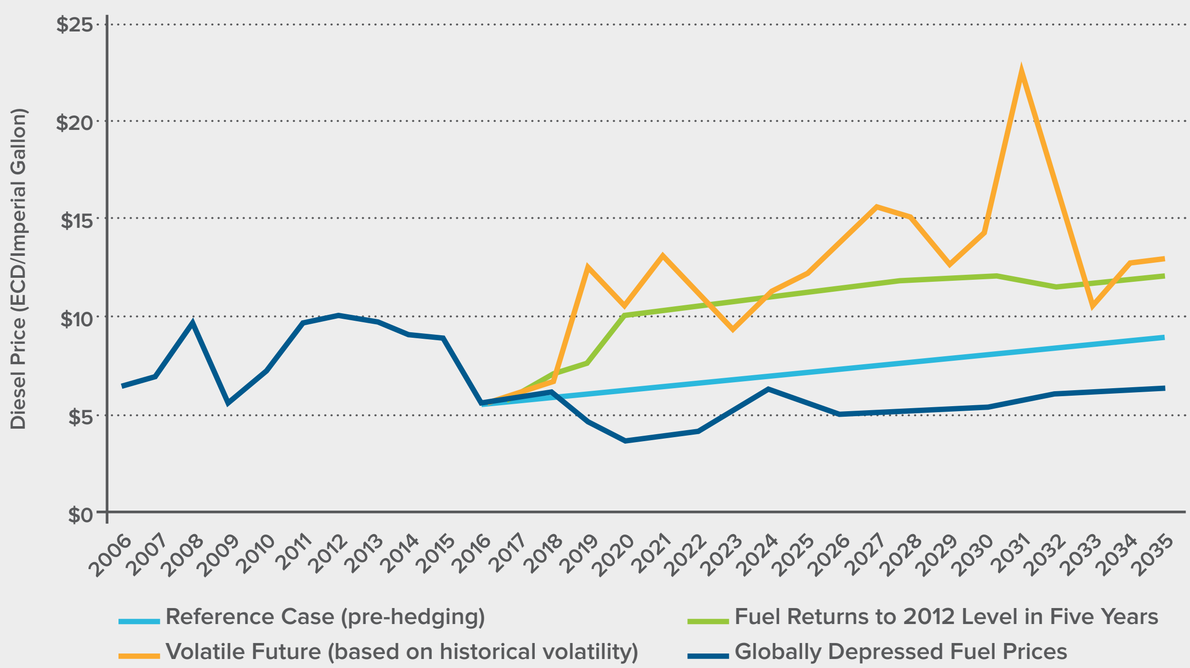
Changing reserve requirements modifies the amount of new resources that are part of the economically optimal mix by up to three times and changes the operation of resources.

The HOMER modeling tool allows for setting reserve margins, either in relation to peak load or to provide reserves to back up any variable renewables. The original settings used in the analysis were quite conservative, at “n-2” related to peak load in addition to 100 per cent of current renewable energy production. These settings were adjusted first for the load alone (to 10 per cent of current load in the time step), then for renewable energy production alone (to 25 per cent of current solar and 50 per cent of current wind production).

The NETS team agreed on the final settings, adjusting both settings in the model (to 10 per cent of current load, 50 per cent of current solar production, and 75 per cent of current wind production). Testing alternative approaches to reserve requirements reveals the degree to which this variable affects

**FIGURE 33**

FUEL PRICE INPUTS FOR SENSITIVITY TESTING (ORANGE LINE REPRESENTS HISTORICAL)



results. The amount of storage included in the economically optimal mix for the solar-only scenario is impacted greatly by the choice of operating reserve requirements, as shown in Figure 34.

Changing assumptions about the operating reserve margin also modifies predicted system operations once variable renewables enter the Saint Lucia grid.

As seen in Figure 35, given a consistent resource mix (30 MW solar and 15 MWh storage), the hourly dispatch is plotted for the day with the greatest decrease in solar output between two hours in the 2019 model (September 6, 28.8 MW to 4.7 MW).

These plots show three options for operating reserve requirements, and how this system operates differently within the model for each. With more conservative settings (option 1), excess solar generation must be curtailed, while options 2 and 3 allow for more of the available solar generation to be utilised and increase total diesel fuel savings as well as diesel operation and maintenance costs.

For more on this analysis, see Appendix N.

**3. *Load forecast:***

Analyzing the selected scenarios with the alternate load forecasts does not significantly change the suggested resource mix within each scenario. This is largely due to flexible generation integrating with existing diesel to serve loads without overcapacity. In particular, solar provides a modular resource, able to grow at the pace of observed load growth.

The team explored multiple load forecasts, modifying projected sales (shown in Figure 36 in kWh) and projected peak demand (shown in Figure 37 in MW). In the reference case, peak demand grows from 59 MW in 2015 to 85 MW in 2035. The high load growth scenario would see a peak demand of 91 MW, with the low scenario growing to 79 MW.

For each different scenario, modifying the load forecast caused minor changes in the amount of economical solar and storage. No major changes to other resources (wind, geothermal, or diesel) occurred due to changes in the load forecast. As shown in Figure 38, these changes grow slightly over time, but do not fundamentally change the recommended scenario (solar, wind, diesel, and low levels of distributed generation).

**FIGURE 34**

STORAGE UNDER DIFFERENT RESERVE CONDITIONS

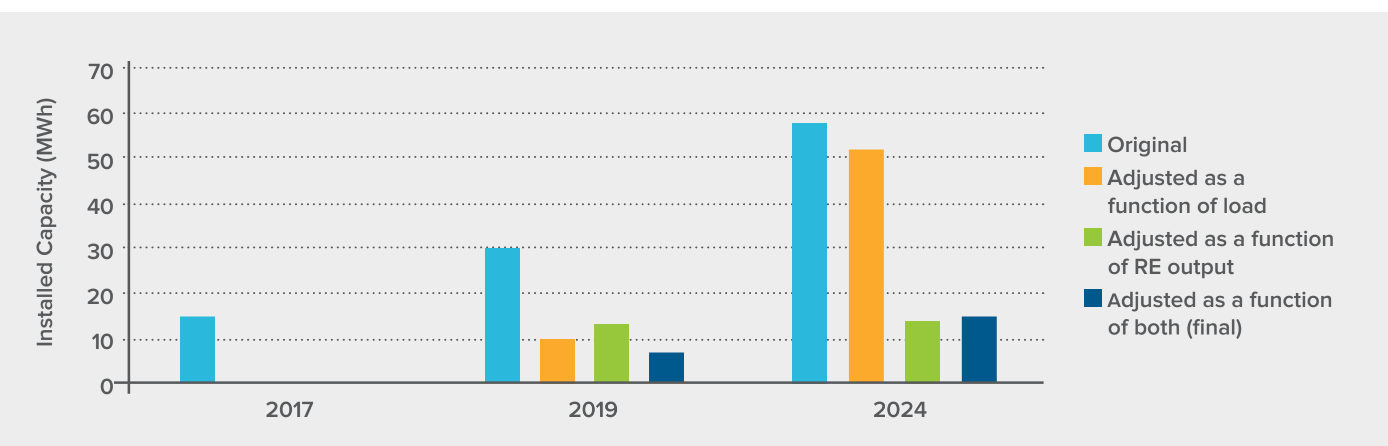


**FIGURE 35**
OPERATION OF GENERATION SOURCES WITH VARYING RESERVES

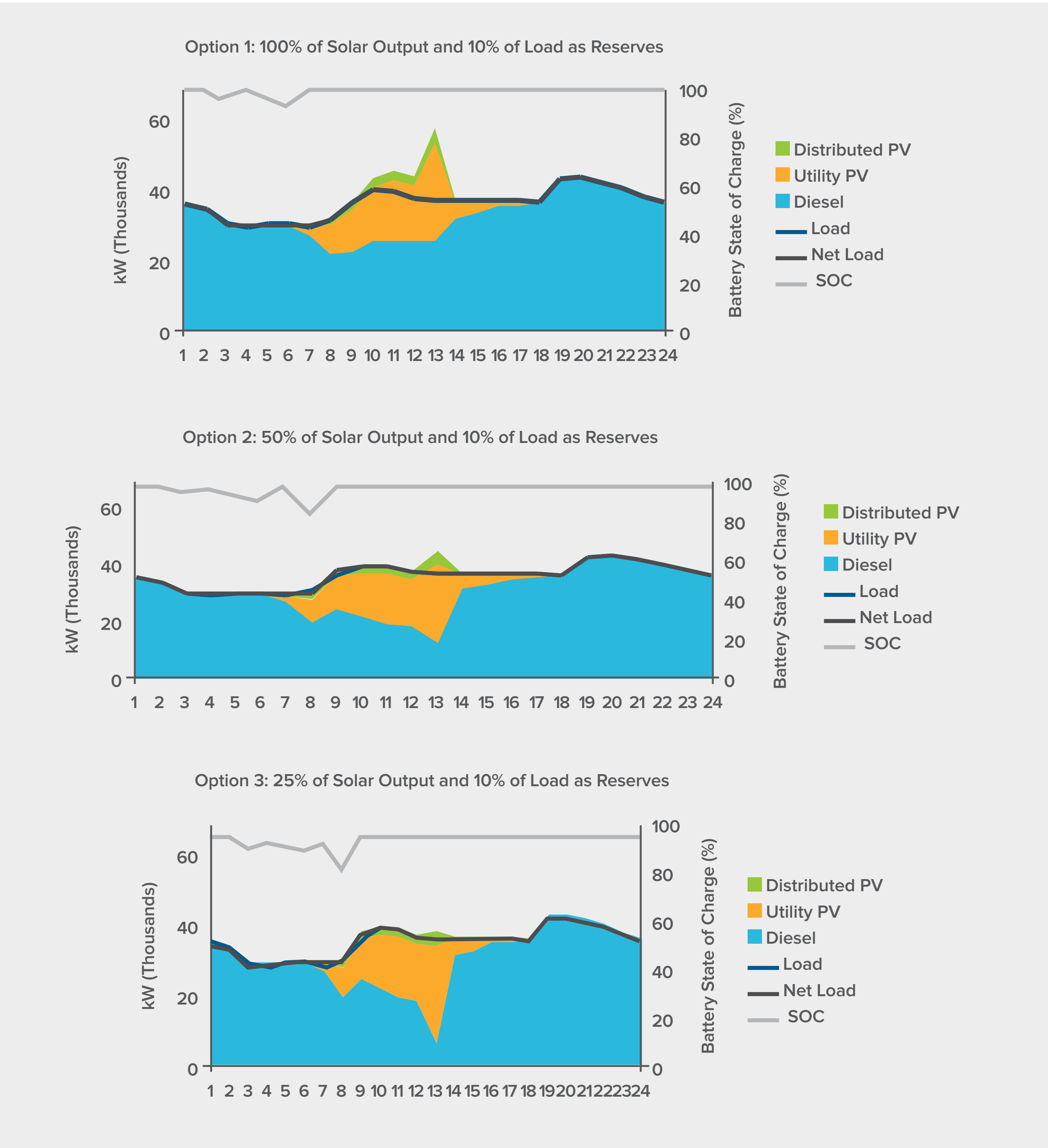


**FIGURE 36**
PROJECTED ANNUAL SALES

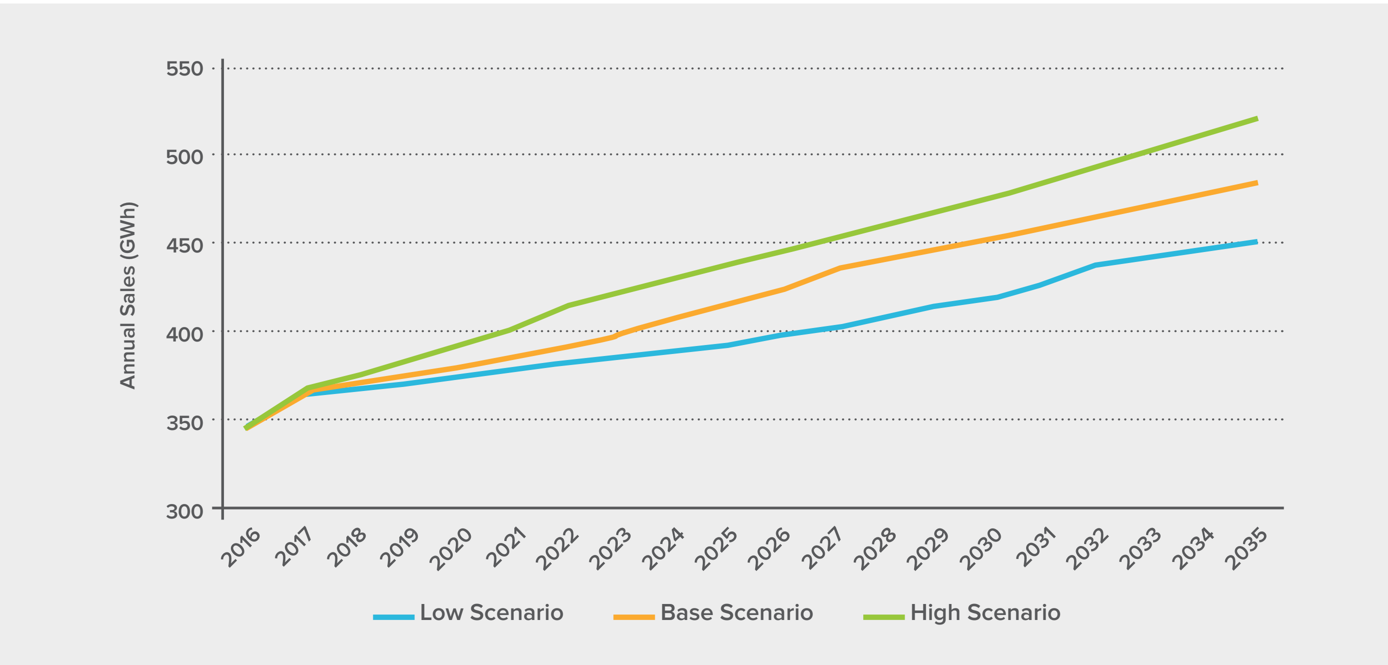



**FIGURE 37**
PROJECTED PEAK DEMAND (IN MW)

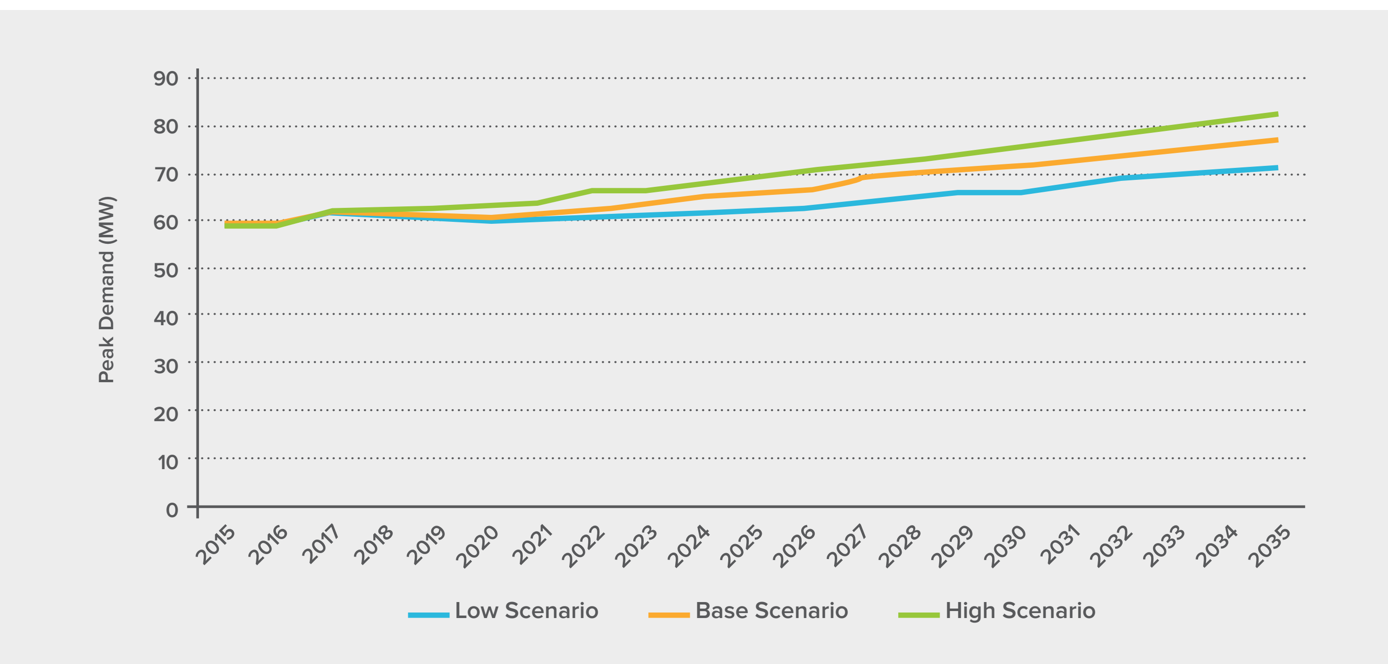
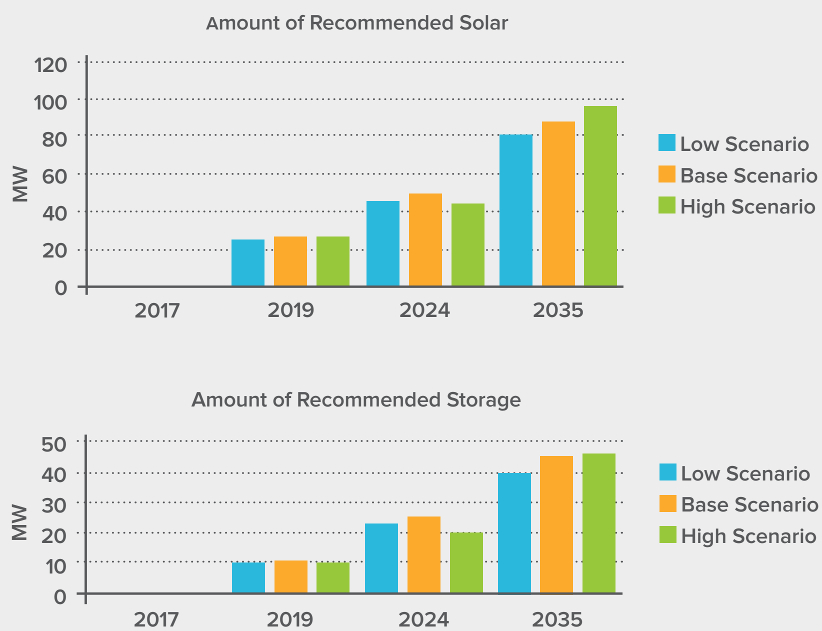


**FIGURE 38**

STORAGE AND SOLAR RECOMMENDED UNDER DIFFERENT LOAD FORECASTS




**4. *Energy efficiency program implementation:***

Analyzing the selected scenarios without the implementation of the energy efficiency program does not significantly change the suggested resource mix within each scenario.

The cumulative effect of energy efficiency is a modification of load by about 11 per cent, with most of the implementation of energy efficiency (through a program) implemented in the coming seven years. Without this energy efficiency resource, peak and average loads will be higher—requiring more installed generation and higher fuel costs. Annual generation with and without implementation of energy efficiency is shown in Figure 39.

However, in terms of decisions required regarding upcoming investments, no major differences appear between scenarios, including those with energy efficiency and those without. Slightly more solar and storage are economical in the 2035 timeframe, but slightly less solar and storage are economical in the 2025 timeframe, as shown in Figure 40.

**5. *Capital and operating costs:***

If capital costs of actual procured renewable resources vary from projected costs, there would be a significant difference in results. However, changing operating costs has only a minor difference.

Higher capital costs (20 per cent increase) for solar, storage, wind, and geothermal PPA prices cause the total cost to operate the system (over the coming 20 years) to increase by 1 to 5 per cent (higher impact for the more renewable scenarios). On the other hand, securing 20 per cent lower cost investments (for solar, storage, wind, and geothermal) can reduce the total cost to operate the system by 1 to 6 per cent over 20 years. These economic results are significant, but not enough to fundamentally change the composition of scenarios.

Higher or lower operating costs—varying again by 20 per cent (due to labor, solar panel cleaning, inverter replacements, wind turbine spare parts, etc.) for new resources (solar, storage, and wind)—modify the total cost to operate the system by less than 1 per cent.

The larger impact on the economics of an energy transition comes from higher or lower capital costs for new investments, with operating costs as a less significant variable.

**FIGURE 39**

LOAD FORECAST WITH AND WITHOUT ENERGY EFFICIENCY

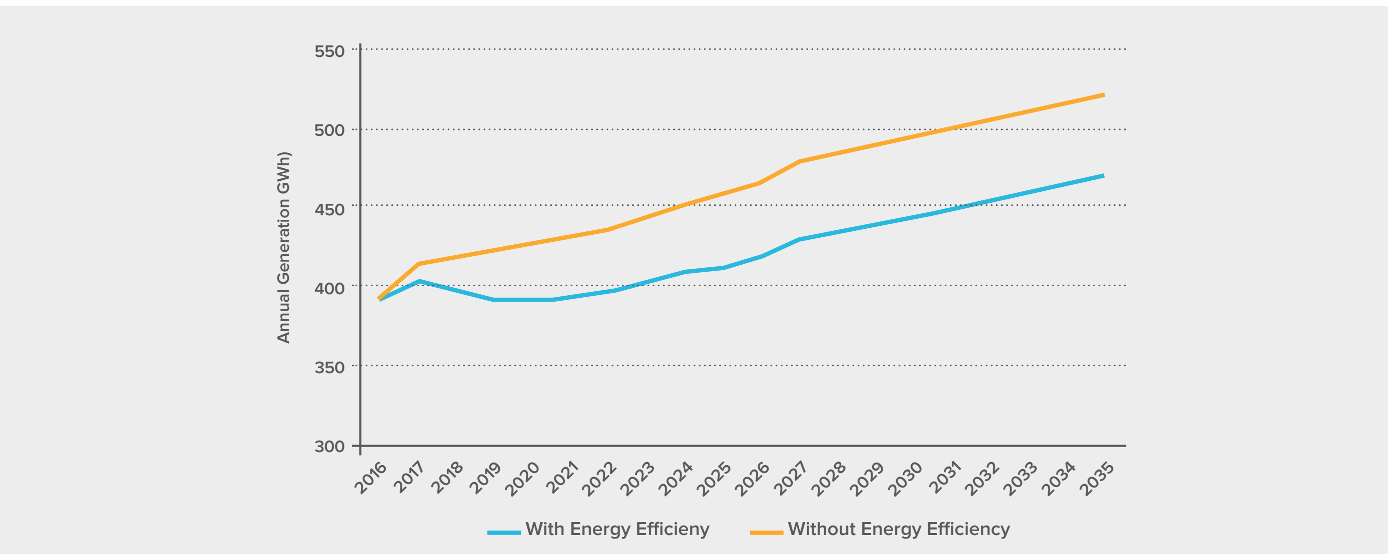
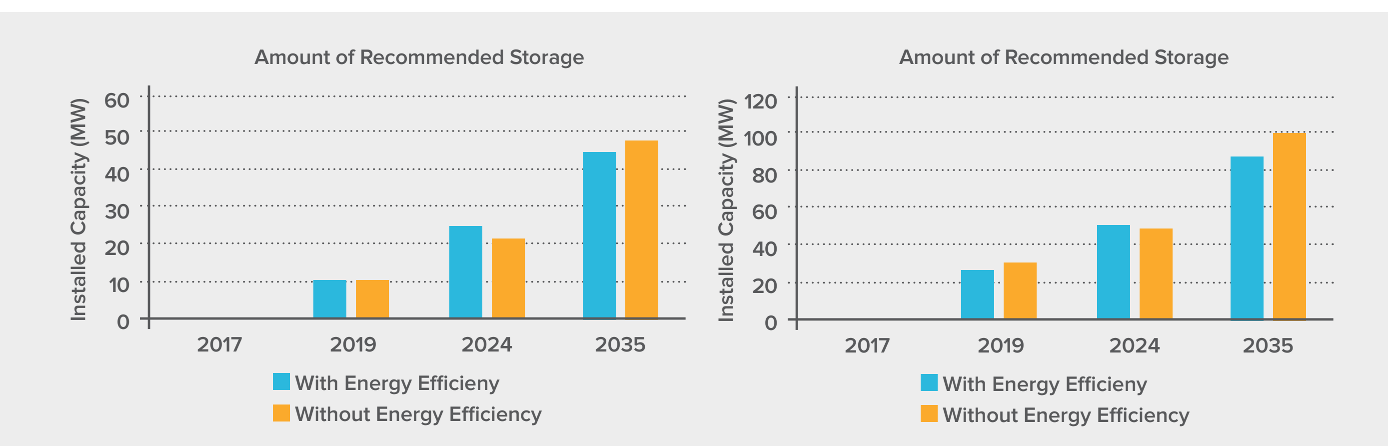



**FIGURE 40**

STORAGE AND SOLAR RECOMMENDED UNDER DIFFERENT ENERGY EFFICIENCY CONDITIONS



03

# NEXT STEPS

# NEXT STEPS

Capturing the benefits outlined above requires a dedicated and concerted set of activities for all stakeholders in the Saint Lucia electricity system. Next steps for LUCELEC include continuing and expanding project development for solar and wind projects, and continuing to participate in geothermal negotiations. Centralised (LUCELEC) ownership of future renewable assets is critical to keep rates down. LUCELEC should also closely examine automated controls to improve generator efficiency and maximise the benefit of adding new resources to the system. Seizing this opportunity requires technical preparation and training and capacity building for staff in new renewable systems. Next steps also include regulatory changes and public participation.

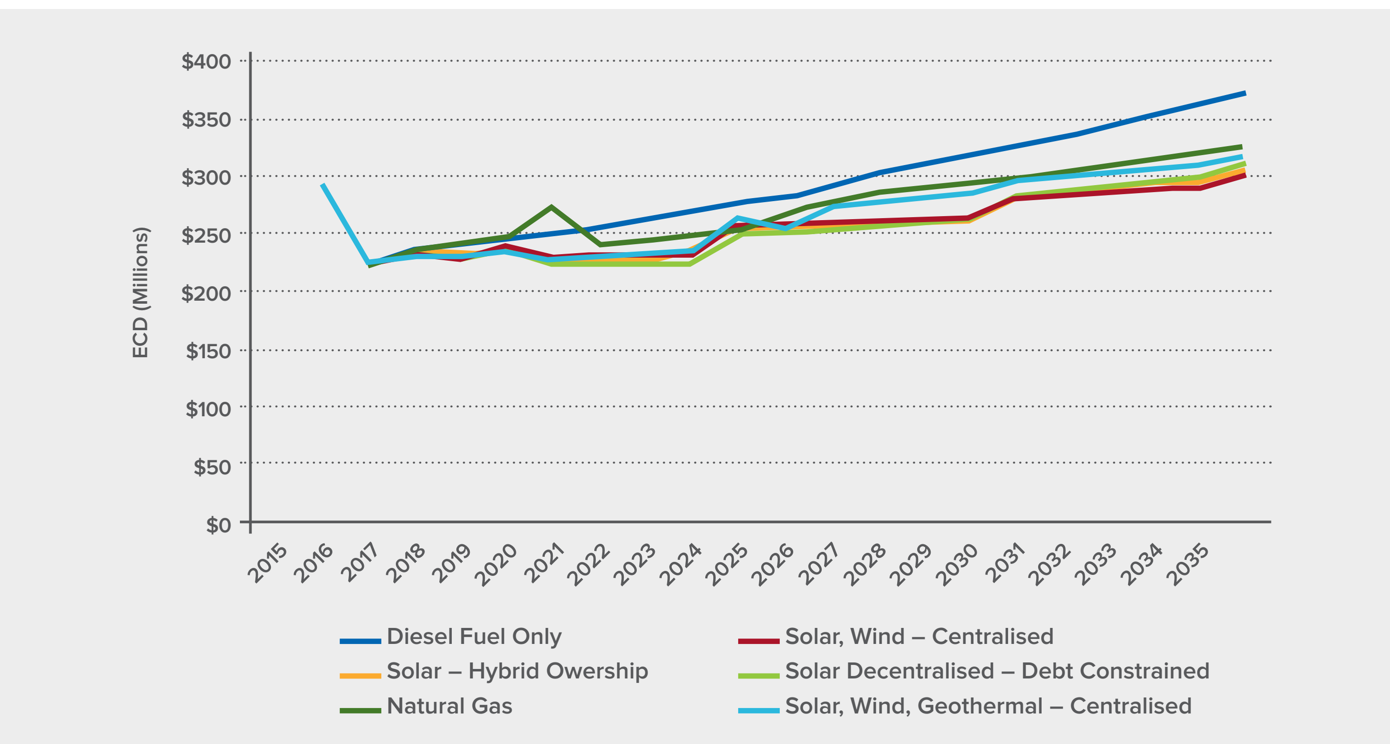
Resources should be phased in gradually over time to ensure debt limitations are not exceeded. Phasing in resources provides a reduction in total cost to operate by 10 per cent over 15 years (see Figure 41).

The NURC plays an important role in ensuring the appropriate phasing in of resources, as well as the right split of distributed generation, third-party participation, and utility ownership of future assets. After reviewing the IRP and associated models, the NURC can seek additional guidance as needed and develop a set of standard regulations for deciding on future projects. Future iterations of the Saint Lucia IRP process should be governed by the NURC.

Lastly, the Government of Saint Lucia holds important roles in project development, regulatory certainty, the advancement of new technology options, and the securing of grant funds. For certain projects, accessing crown land or other government support will be critical,

**FIGURE 41**

COST TO OPERATE - SELECT SCENARIOS BY YEAR



and many government agencies need to be consulted for projects that would occupy valuable land. The Energy Unit of the Government, supported by the relevant Ministers, should support projects commensurate with this plan to benefit the country of Saint Lucia. Ongoing efforts to update laws governing the electricity sector should continue, informed by this analysis and with the full support of all stakeholders. Geothermal or other large projects that require new rate mechanisms should move forward within the coming year. New technologies, such as electric vehicles or carport solar, benefit from government support to pilot and demonstrate their viability. The government should selectively support these types of projects in coordination with the NURC and LUCELEC. Lastly, many of the large projects, including solar and storage, wind, geothermal, and natural gas, require large outlays of capital. Accessing grant funds to support LUCELEC or other actors in funding these projects requires the commitment and persistence of the government. With large funders such as the Global Environment Facility and Green Climate Fund prioritizing small island developing states (SIDS), the Government of Saint Lucia is well positioned to access these funds in the near term.

## FIVE-YEAR PLAN

The five-year plan for the NETS depends on advancing select projects that work well under the recommended scenario, as well as alternative options such as geothermal and natural gas. These projects begin the process of testing technologies, building expertise in procurement and operations, lowering costs, and demonstrating progress toward a low-cost, reliable, and energy-independent future.

### SOLAR AND STORAGE

LUCELEC should bring on 20 MW of solar in the next five years. Future projects can be installed on available land, parking areas, and large rooftops (attempting to minimise cost). The economics of additional solar at that point will depend on geothermal progress and the costs of competing technologies, which are expected to continue to fall. This creates a 5 per cent rate relief (in 10 years) and reduced volatility, without any risk to reliability. Currently, LUCELEC is leading a project to develop 3 MW in Vieux Fort, and up to 7 MW are possible in the coming years through distributed generation (with the right policies). Therefore, per the NETS results, LUCELEC can install an additional 18 MW of solar cost-effectively over the next five years (depending on the pace of distributed generation adoption), and then reexamine system implications. Building on the findings from the successful solar project in Vieux Fort, a faster and more efficient project development and procurement process will improve economics.

Solar and storage could become a dispatchable resource over time—up to 28 MW of solar, 20 MW of which can be considered “no regrets” investments—independent of securing a low-cost geothermal resource. Under current assumptions, solar plus storage outcompetes both new geothermal and existing diesel for meeting new load as the total system load grows. However, adding solar and storage to produce beyond 30 per cent of annual generation is not cost competitive until storage costs decrease.

LUCELEC should start with a 3 MWh energy storage pilot project, growing to 14 MWh in 2020, and then up to 27 MWh by 2025. Energy storage will provide operating reserves and improve the dispatch of current diesel generators (and thereby fuel efficiency), reducing fuel use by 0.5 per cent before the addition of renewable resources. Sited strategically, energy storage can also reduce feeder congestion during demand peaks, and defer transmission and distribution upgrades. When combined with solar, energy storage provides additional value in firming this variable resource, resulting in an additional 2 per cent savings in fuel use.

Figure 42 demonstrates how resources might be dispatched in 2024 in a system containing both utility-owned and distributed solar, along with storage.

## AUTOMATED CONTROLS

LUCELEC should invest in automated controls to improve generator efficiency and maximise the benefit of new resources. Current manual dispatch leads to imperfect dispatch strategies. Even in today's system without renewables, automated controls create fuel savings and result in approximately 3 per cent improvement in average generation efficiency. With new renewable and storage systems in place, improved dispatch strategies will have increased importance to keeping costs down.

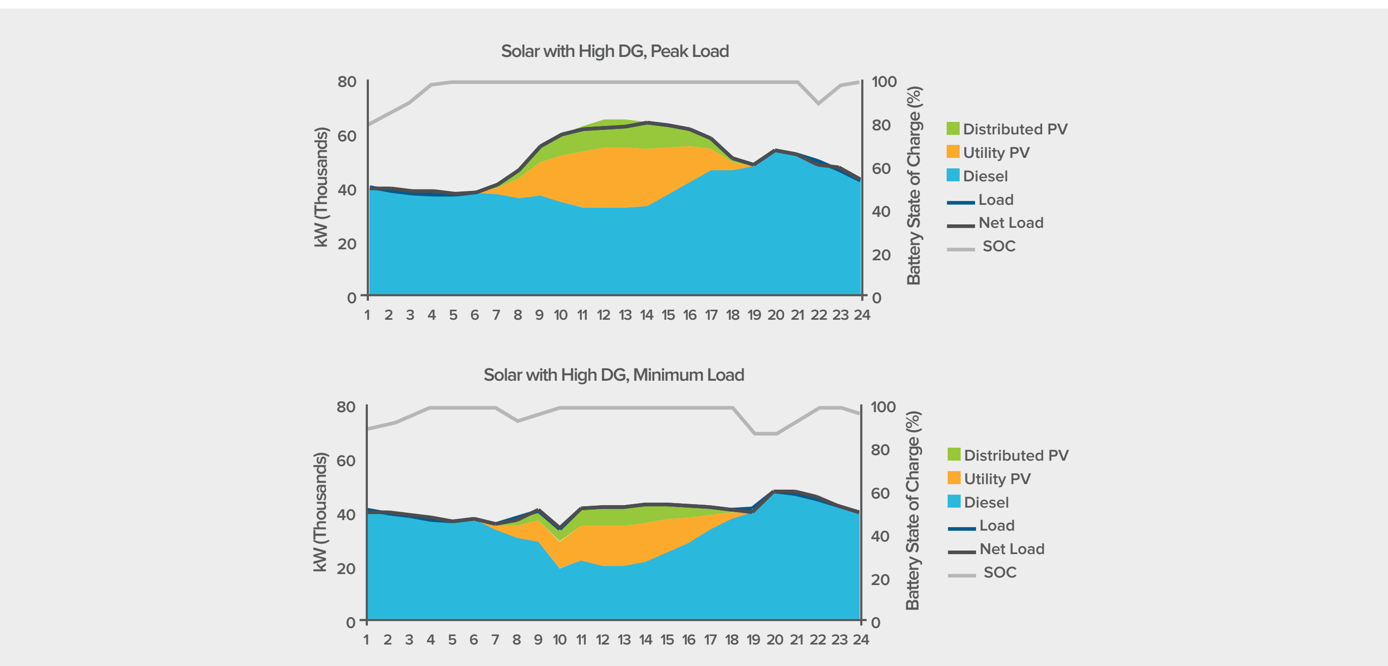
In the future, automated controls combined with smart inverters for solar or energy storage will improve system response to sudden changes in generation or load. Controls can also be integrated with automated demand response programs. Previous demand response programs relied upon manual operation of standby diesel generators owned by hotels (up to a maximum of approximately 11 MW). Future demand response programs should explore automatic (remote controlled) activation of standby generators or the reduction of demand from select customer equipment (hot water heaters, pool pumps, etc.).

## WIND AND GEOTHERMAL

Wind and geothermal should be developed only as they prove their potential to be cost-effective. Both the immediate Dennery Bay project and the Soufrière geothermal project will require thorough due diligence and continued investment from LUCELEC. LUCELEC should explore ownership of the Dennery wind farm or negotiate a lower PPA price. The proposed Dennery Bay wind project does not compete with existing diesel or other options at the proposed PPA price (EC$0.49/kWh). A price between EC$0.36/kWh and $0.38/kWh

**FIGURE 42**

DISPATCH OF DIESEL, SOLAR, AND STORAGE IN 2024



would create parity with the optimal scenario. Other wind projects in Vieux Fort and Pigeon Point should be explored (per prior wind resource assessments).

LUCELEC should also continue to develop geothermal options, taking the necessary steps to ensure low PPA prices to benefit the country. Geothermal currently appears to be a potential option in order to reach higher penetrations of renewable energy, secure energy independence, and reduce risks due to fuel volatility, but it requires a lengthy development time. The primary benefit that geothermal offers is an ability to serve as a base-load resource (operating and providing power consistently over time) combined with dispatchability (ability to increase or decrease power when needed) (see Figures 43 and 44).

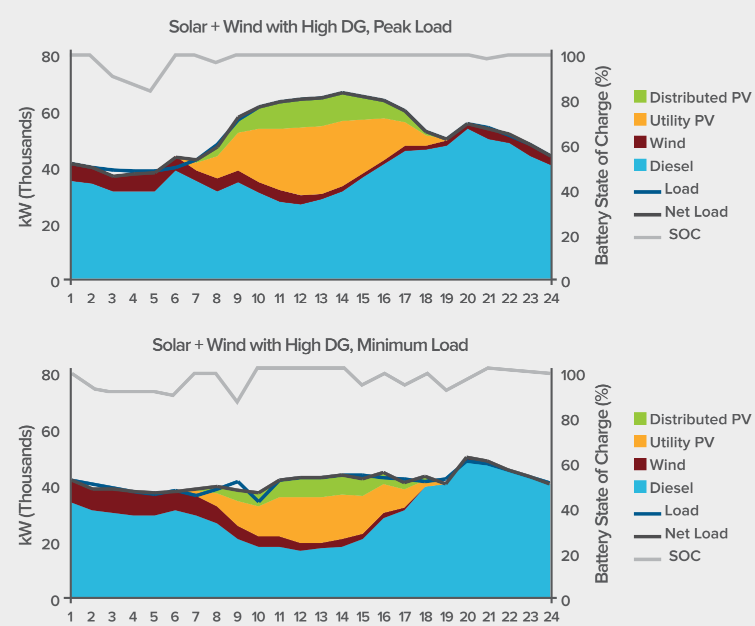
A lower PPA price (approximately EC$0.38/kWh) would make geothermal economical under a wide range of diesel prices. Securing this lower price requires technical preparation (including test drilling and geotechnical studies), which when financed through low-cost development funds could benefit the country through reduced rates.

Operating the system with wind, solar, storage, and diesel—or with a mix including baseload power from geothermal, supplemented by diesel, wind, less solar, and storage—is a technical task well suited for LUCELEC's capabilities and expertise. New generation schemes would require automated controls on diesel generators, as well as software systems to ensure battery dispatch at appropriate times.

The charts in Figures 43–45 display system operations at peak and minimum load conditions, with a variety of generation resources providing power and battery storage accommodating any variability in wind and solar while smoothing out diesel generators (often preventing an additional generator from turning on).

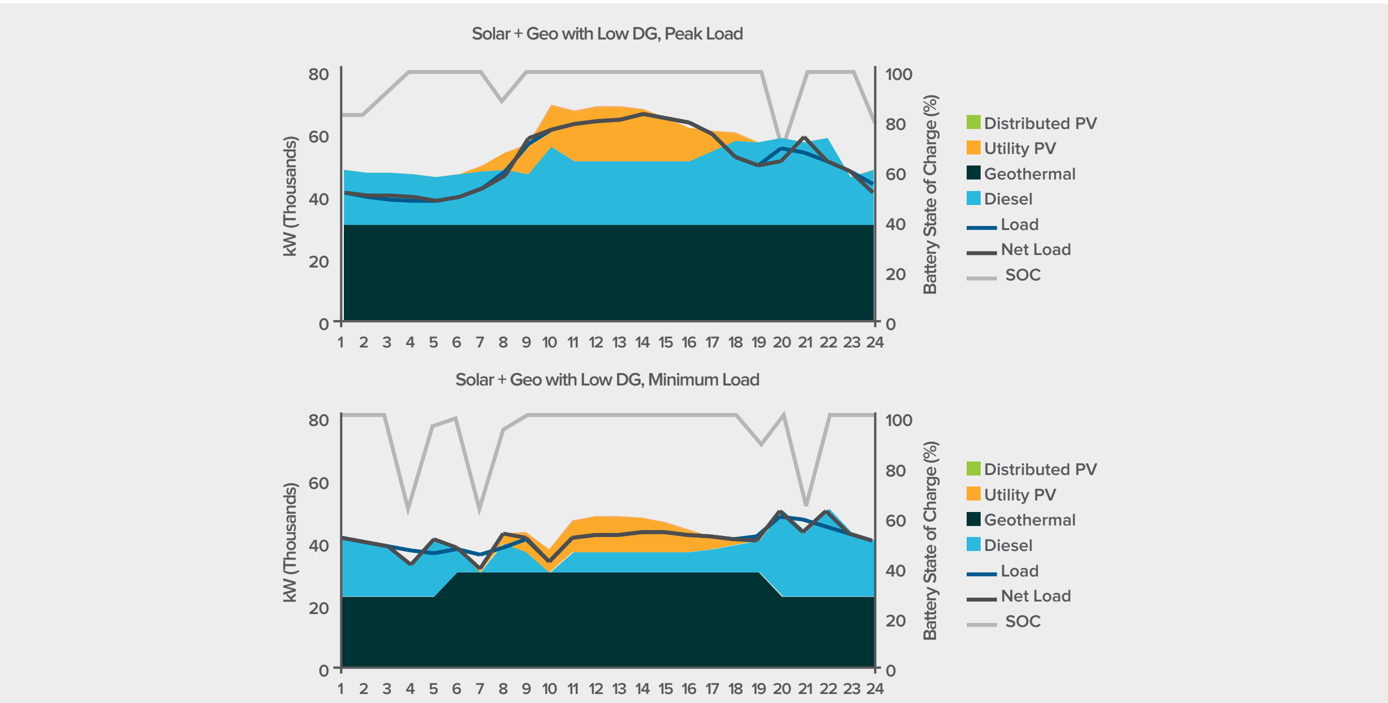
**FIGURE 43**

DISPATCH OF DIESEL, SOLAR, WIND, AND STORAGE IN 2024



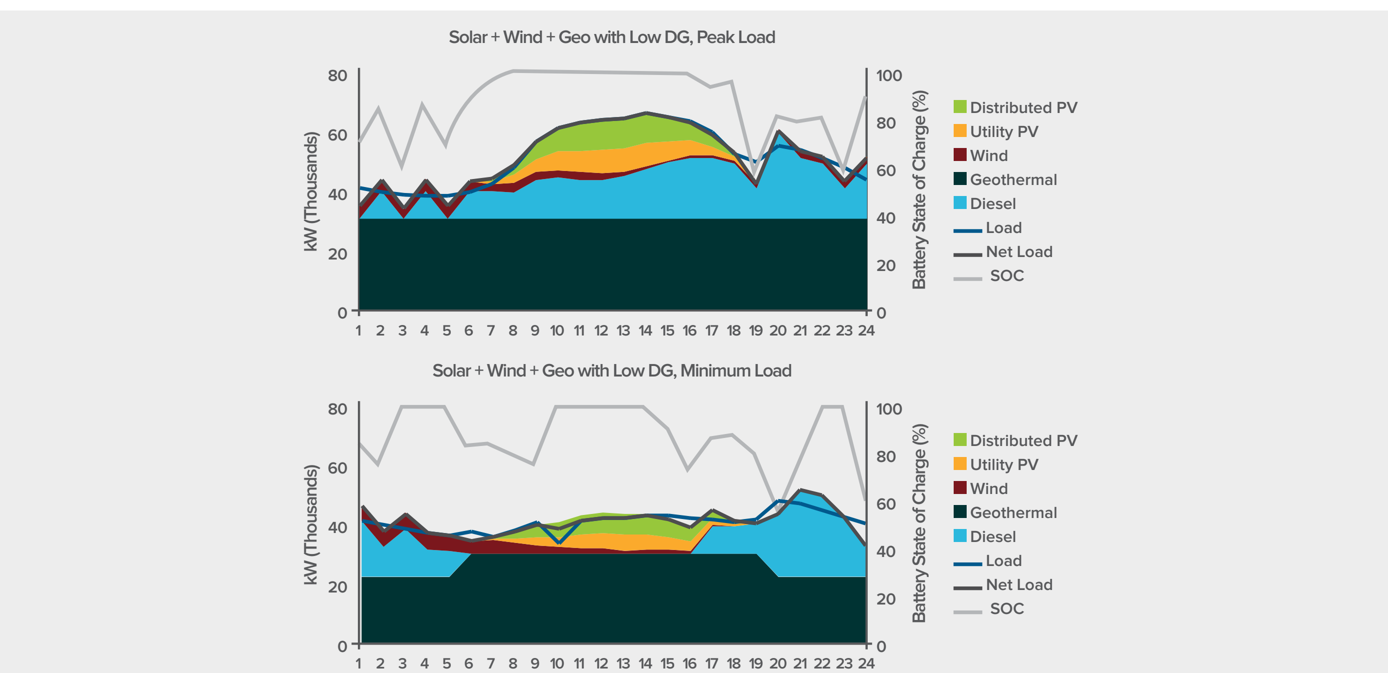
## FIGURE 44

DISPATCH OF DIESEL, SOLAR, GEOTHERMAL, AND STORAGE IN 2024



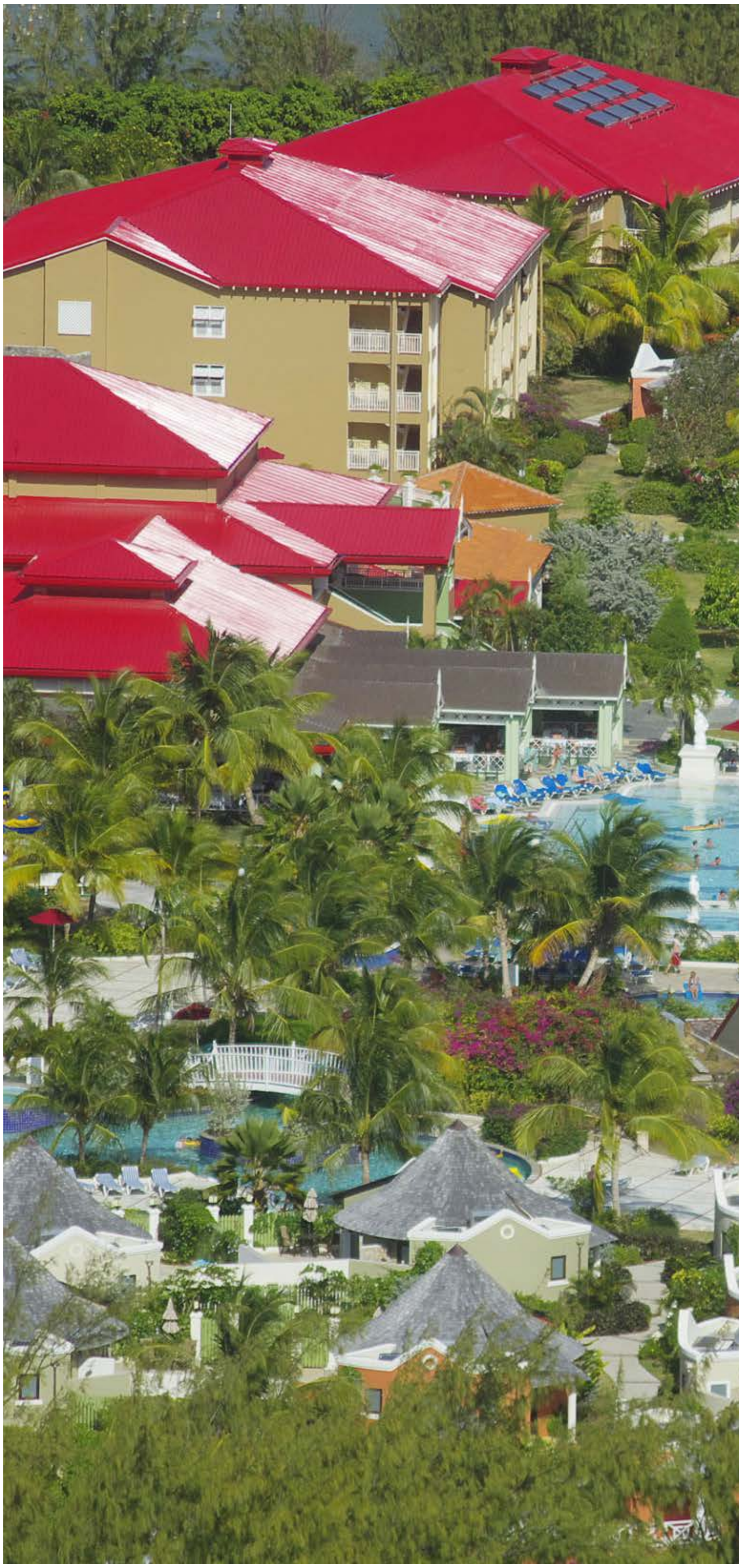

## FIGURE 45

DISPATCH OF DIESEL, SOLAR, WIND, GEOTHERMAL, AND STORAGE IN 2024



### UTILITY-DRIVEN ENERGY EFFICIENCY PROGRAM

Energy efficiency should be pursued through a targeted program to reduce loads by 0.5 per cent per year (11 per cent in 10 years). This will include replacing existing incandescent and CFL bulbs with LEDs, switching out inefficient refrigerators, and targeting the large loads at hotels with lighting, cooling, and solar water heating strategies in a program supported by LUCELEC. The NURC needs to provide incentives to LUCLEC and consumers to capture this low-cost resource. This approach would cost between EC$100 million and $125 million over 10 years, at a total cost of between EC$0.14 and $0.19 per kWh saved (installed costs and program administration). Total savings to customers would be in excess of 800,000 MWh in the coming 20 years, with reduced costs on the order of 10 per cent.



## REGULATORY CHANGES

Seizing this opportunity requires regulatory change. A functioning electricity system requires a financially viable utility to provide system control, ensure safety and reliability, and create parity among customers. LUCELEC has been historically profitable, well managed, and effective at keeping rates down. However, energy efficiency could erode LUCELEC's profitability and effectiveness if the NURC does not create mechanisms that compensate LUCELEC for energy efficiency. This could include program cost recovery, performance incentives, and/or lost margin recovery. The NURC and LUCELEC should also examine more thorough approaches to changing utility business models.

The NURC should establish a mechanism for recouping utility investments in renewable energy to allow LUCELEC to develop renewable energy generation while benefitting its customers.

Despite higher rates paid by customers, distributed generation offers benefits through reduced system cost and customer participation, and should be implemented to a degree. Caps on the maximum amounts of installed distributed generation and individual system limits are important as high penetration of distributed generation could impact the reliable operation of the grid as well as the profitability of LUCELEC. The profitability impact would not be materially felt unless fuel prices or customer defection (due to cheap solar and storage) materially shift the landscape. Therefore, LUCELEC should work with the NURC to determine optimal caps and revisit them periodically to ensure a managed energy transition. It will be critical to determine a fair rate for power purchased from distributed generators.

## PUBLIC PARTICIPATION

Engaging the public is key for the energy transition process. Concerns about LUCELEC's future participation in the renewable energy space as well as the independence of the NURC have been expressed during public consultations conducted as part of the NETS process. Recent public consultations and editorials have also demonstrated some skepticism and unhappiness with caps on customer-owned solar.

Transparency often forms a key principle of electricity system evolution. To reduce customer skepticism about the projects currently underway, the NURC should carefully enable customer ownership of and participation in the renewable transition. Articulating clearly the reasons for customer participation and the positive and negative economic implications will help with public perception. LUCELEC, in coordination with the NURC, should clearly communicate rate impacts, specifically who will be impacted and how they will be impacted. Without public buy-in, projects can stall, particularly for visible projects such as wind or projects in high tourism areas such as geothermal.

The Government of Saint Lucia must also maintain open discourse with the public and encourage participation. However, in the context of negotiations with developers, special care must be taken to ensure Saint Lucia/LUCELEC get the best possible result (often requiring careful negotiation and the use of leverage).

Participation from all sectors will allow broader progress on the energy transition:

- Energy efficiency and distributed generation, as enabled by the NURC, will allow customers to reduce their bills and increase their control over electricity expenses.
- Local solar providers will be involved in the development of additional utility-scale solar.
- IPPs, involving local firms, may participate in additional wind projects in the future.

Continued public input regarding the NETS will emphasise the independent approach to designing this strategy. An upcoming in-depth public consultation will be transparent with the process and the results of the planning phase.

AP

# APPENDICES

# APPENDICES

## APPENDIX A: UNIT CONVERSIONS

### CURRENCY AND PRICES

All dollar figures are in money of 2015 (the reference year), unless otherwise noted

Currency Unit = Eastern Caribbean Dollar (ECD) or (EC$)
United States Dollar US$1.00 = EC$2.70

### MEASURES AND EQUIVALENTS

1 kilometre = 0.6214 miles (m)
1 ton = 1,000 kilogram (kg) = 2,200 pounds (lb)
1 kilovolt (kV) = 1,000 volts (v)
1 megawatt (MW) = 1,000 kilowatts (kW)
1 kilowatt hour (kWh) = 1,000 watt-hours (Wh)
1 gigawatt hour (GWh) = 1,000,000 kilowatt-hours (kWh)
1 kilocalorie (kcal) = 3.97 British Thermal Units (BTU)

### MULTIPLYING FACTORS FOR CONVERSION OF PETROLEUM UNITS

| | U.S. Gallons (gal) | UK Gallons (gal) | Barrels (bbl) | Metric Tonnes (t) | Litres (l) |
|---|---|---|---|---|---|
| U.S. gallons (gal) | 1 | 0.8327 | 0.02381 | 0.00325 | 3.785 |
| UK gallons (gal) | 1.201 | 1 | 0.02859 | 0.0039 | 4.546 |
| Barrels (bbl) | 42.00 | 34.97 | 1 | 0.1366 | 159.00 |
| Metric tonnes (t) | 308.00 | 256.00 | 7.32 | 1 | 1164.00 |
| Litres (l) | 0.2642 | 0.220 | 0.0063 | 0.000859 | 1 |
| Cubic metres ($m^3$) | 264.20 | 220.00 | 6.289 | 0.8591 | 1000.00 |

Source: IEA

## APPENDIX B: GLOSSARY

| | |
|---|---|
| BTU | British Thermal Units |
| CDSPS | Cul De Sac Power Station |
| DR | Demand response |
| DNV GL | DNV GL—an independent engineering firm |
| EACT | Energy & Advanced Control Technologies |
| ECD | Eastern Caribbean Dollar. All dollars in this report are Eastern Caribbean Dollars unless otherwise noted. There are 2.7 Eastern Caribbean Dollars per U.S. dollar. |
| ECERA | Eastern Caribbean Energy Regulatory Authority |
| EE | Energy efficiency |
| Ft | Feet |
| gal | Imperial gallon. There are approximately 1.2 US gallons in an Imperial gallon. Imperial gallons are the typical gallon used on Saint Lucia. |
| GDP | Gross domestic product |
| HOMER | HOMER Energy, LLC |
| IPP | Independent power producer |
| IRP | Integrated resource plan |
| kV | Kilovolt (a unit of voltage, commonly used with T&D systems) |
| kW | Kilowatt (a unit of power). When used in units this is typically kW based on nameplate rating. |
| kWh | Kilowatt-hours (a unit of energy). 1 kWh = 1000 Wh. |
| LED | Light-emitting diode (a lighting system type) |
| LCOE | Levelised cost of energy, a measurement of the cost of energy including lifetime and investment costs ($/kWh)—typically expressed in ECD/kWh in this report |
| LNG | Liquefied natural gas |
| LUCELEC | Saint Lucia Electricity Services Limited |
| MCG | Meister Consulting Group |
| MW | Megawatt (a unit of power = 1000 kW) |
| NETS | National Energy Transition Strategy |
| PPA | Power purchase agreement |
| PV | Photovoltaic, specifically solar generation |
| RE | Renewable energy |
| T&D | Transmission and distribution |
| Wh | Watt-hours (a unit of energy). 1 kWh = 1000 Wh. |
| Yr | Year |

# APPENDIX C: INPUTS AND ASSUMPTIONS

## FINANCIAL ASSUMPTIONS:

- Study Period – 20 years
- Discount Rate – 5%
- Inflation Rate – 0.5% (Eastern Caribbean Central Bank)
- LUCELEC Cost of Debt – 8% (LUCELEC)
- LUCELEC Cost of Equity – 3% (LUCELEC)
- Weighted Average Cost of Capital – 5%
- Debt Term – 15 years (LUCELEC)
- Depreciation Approach – Straightline
- Tax Rate – 30%

**FIGURE C1**

MODEL INPUTS FOR HOMER LEAST-COST SUPPLY MODEL (EASTERN CARIBBEAN DOLLARS)*

| Input | Units | 2015 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| Solar Installed Cost | $/kW | 7,724 | 5,685 | 5,589 | 5,561 | 5,605 |
| Wind Installed Cost | $/kW | 7,840 | 7,172 | 7,076 | 6,379 | 6,293 |
| Storage Installed Cost | $/kWh | 3,240 | 1,851 | 1,389 | 1,157 | 926 |
| Geothermal PPA Price | $/kWh | 0.45* | 0.45* | 0.45* | 0.45* | 0.45* |
| Fuel Price | $/IG | 8.86 | 6.46 | 7.18 | 8.14 | 9.18 |
| Units Generated | kWh/day | 1,057,384 | 1,070,715 | 1,127,806 | 1,215,407 | 1,287,674 |

*Costs include land cost (solar and wind) and T&D costs (wind and geothermal), but exclude VAT and service charge (per prior agreement with all parties).

Many inputs were incorporated, fuel price being one of the most important. Fuel price projections were based on future markets forecasts and historical volatility.

LUCELEC currently supplies its customers with electricity generated from diesel fuel. The international oil (diesel) market is volatile. The economy of Saint Lucia is therefore hinged on this volatility. To reduce volatility to customers, LUCELEC embarked upon a hedging strategy in 2009. This allowed 75 per cent of its fuel cost to be established via swaps. Whether LUCELEC hedges or not, the cost of fuel is passed through to the customers.

LUCELEC's hedging objectives were met, in terms of gaining a degree of certainty and steadiness in fuel costs for three months at a time. For the most part, LUCELEC's hedging strategy has worked in its favor, and by extension for the people of Saint Lucia. However, there were times when the international fuel price plummeted and LUCELEC was locked into fixed hedging commitments.

Starting in 2016, LUCELEC targets hedging 50 per cent of purchased fuel via options. The true financial benefit can only be determined in hindsight. The cost of this premium is estimated to be a 3 per cent adder to the price of fuel (based on historical performance).

**FIGURE C2**

HISTORICAL FUEL COST VS. FUEL PROJECTIONS

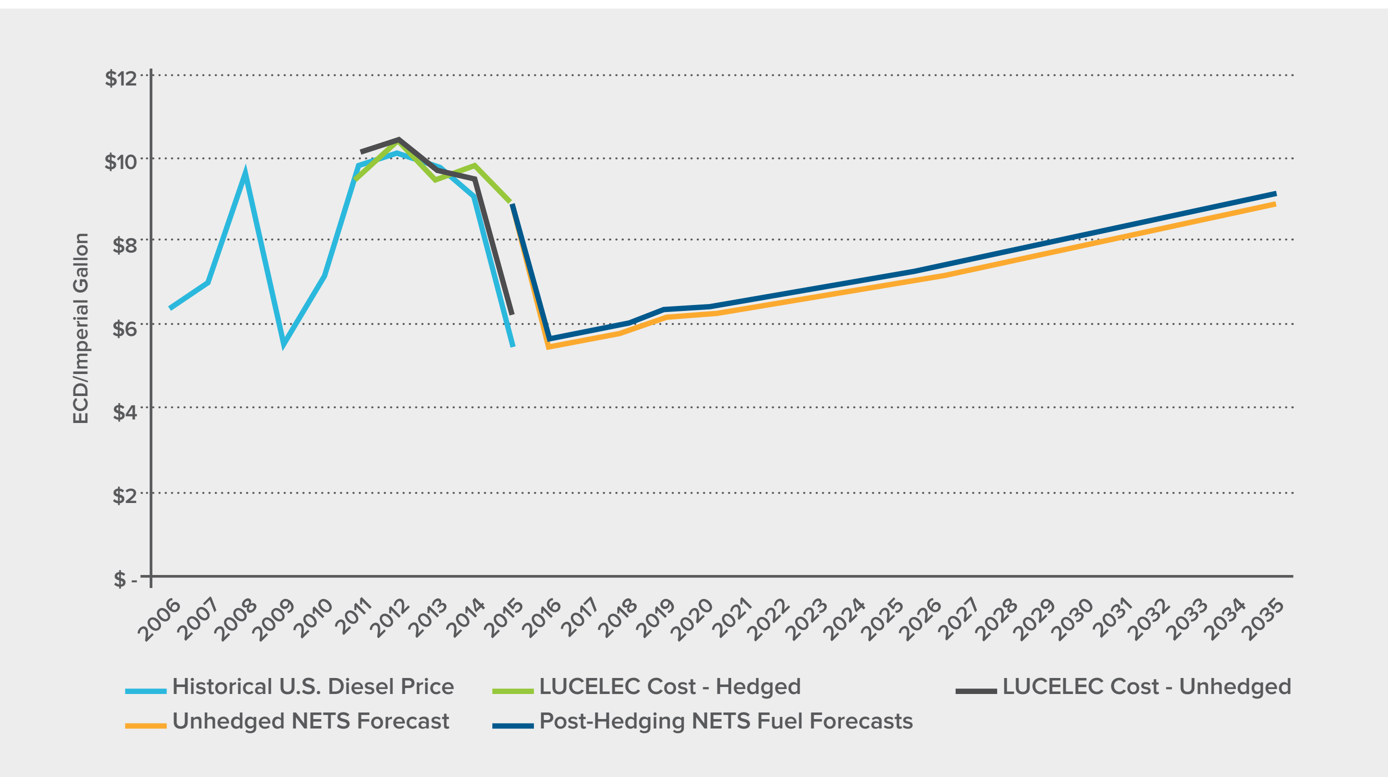


**FIGURE C3**

POPULATION GROWTH AND DENSITY

| | Saint Lucia Population | Growth Rate | Density/sq. km | Density Growth Rate/Yr |
|---|---|---|---|---|
| 2016 | 186,000 | 0.787% | 323.2 | 1% |
| 2030 | 205,000 | 0.539% | 380.3 | 1% |
| 2060 | 220,000 | -0.028% | 408.1 | 0% |

**FIGURE C4**

JOBS BY CATEGORY

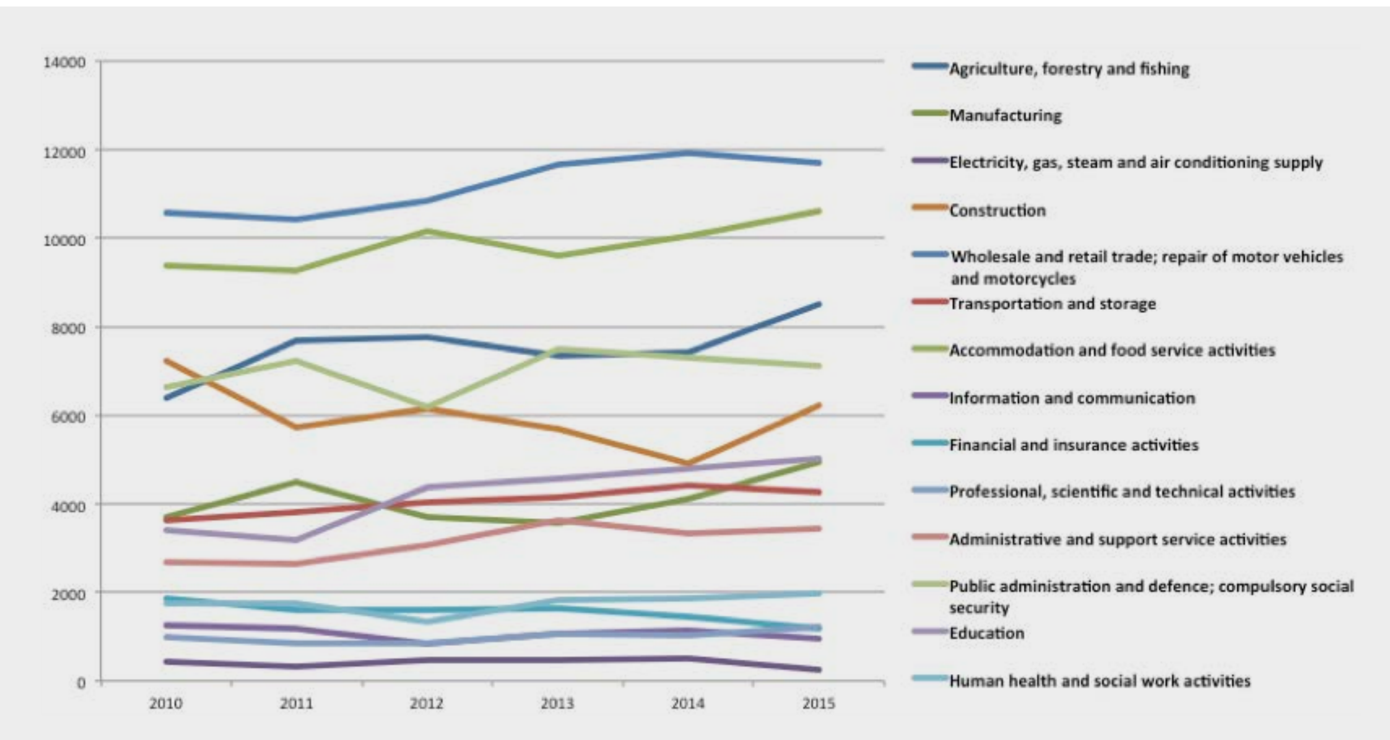


**FIGURE C5**

GDP CONTRIBUTION BY SECTOR

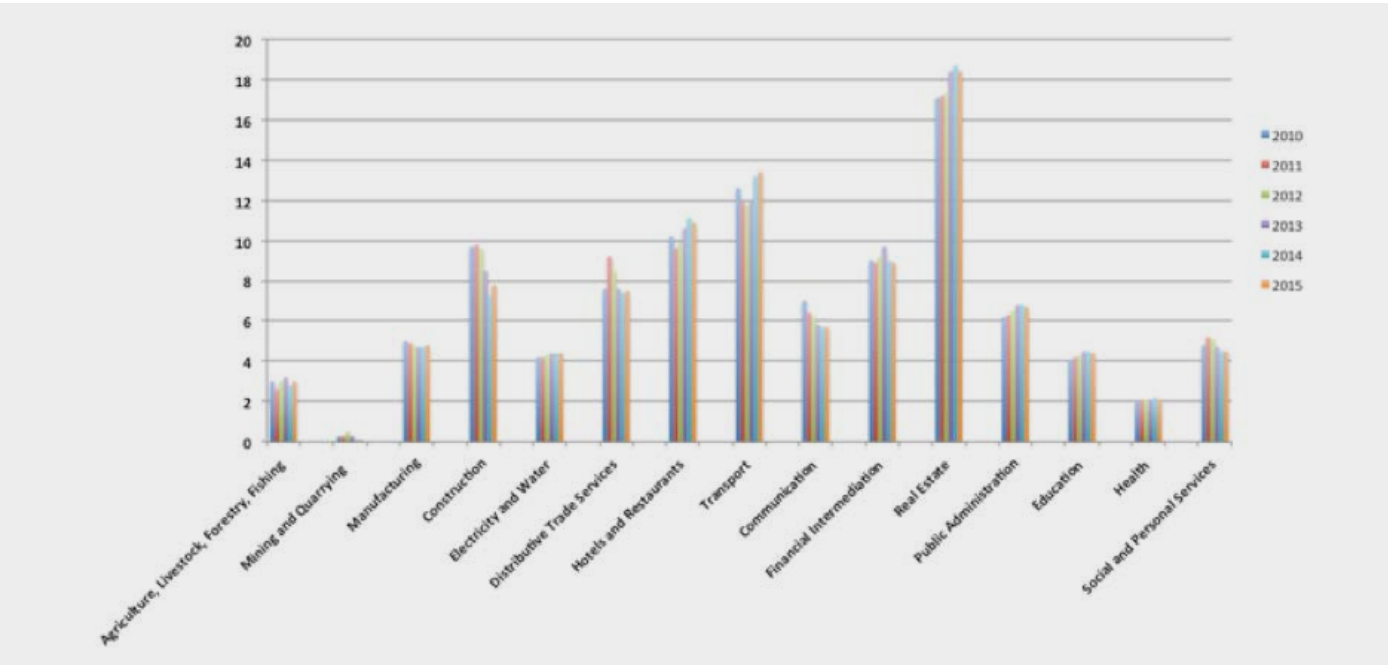



**TABLE C1**

PROPOSED LAND DEVELOPMENTS

| GOSL Developments | Total Acreage |
|---|---|
| La Fargue, Choiseul | 2.5 |
| Piaye, Laborie | 4 |
| Canelles, Vieux Fort | 24 |
| Forestiere, Castries | 14 |
| Aux Lyons, Dennery | 6 |
| Canaries | 57 |
| Monier, Gros Islet | 2 |
| Ti Rocher, Micoud | 13 |
| Total GOSL Developments | 122.5 |
| **Private Developments** | **Total Acreage** |
| Residential | 100 |
| Commercial | 20 |
| Total Private Developments | 120 |
| Total Projection | 242.5 |

## APPENDIX D: DIESEL GENERATOR INFORMATION

**TABLE D1**
DIESEL GENERATORS

| Station | Unit | Type | Nameplate Capacity (MW) | Available Capacity (MW) | Year of Installation | Expected Retirement Year |
|---|---|---|---|---|---|---|
| A | CDSPS#1 | MaK / 6M601 | 6.30 | 6.00 | 1990 | 2019 |
| A | CDSPS#2 | MaK / 6M601 | 6.30 | 6.00 | 1990 | 2019 |
| A | CDSPS#3 | MaK / 6M601C | 7.00 | 6.40 | 1994 | 2019 |
| B | CDSPS#4 | Wartsila / 12V46 | 9.30 | 9.30 | 1998 | 2023 |
| B | CDSPS#5 | Wartsila / 12V46 | 9.30 | 9.30 | 1998 | 2023 |
| B | CDSPS#6 | Wartsila / 12V46 | 9.30 | 9.30 | 1998 | 2023 |
| B | CDSPS#7 | Wartsila / 12V46 | 9.30 | 9.30 | 2000 | 2025 |
| C | CDSPS#8 | Wartsila / 12V46 | 10.20 | 10.20 | 2007 | 2030 |
| C | CDSPS#9 | Wartsila / 12V46 | 10.20 | 10.20 | 2005 | 2032 |
| C | CDSPS#10 | Wartsila / 12V46 | 10.20 | 10.20 | 2012 | 2037 |
| Mobile | CAT#1 | Caterpillar | 1.10 | 1.10 | | |
| Mobile | CAT#2 | Caterpillar | 1.10 | 1.10 | | |
| System Totals: | | | 89.60 | 88.40 | | |

Cat#1 and Cat#2 are currently located at a temporary installation, the Belle Plaine Power Station, in Soufrière.

**TABLE D2**

MODELED AVERAGE GENERATOR EFFICIENCY (BASED ON IMPLIED HEAT RATES)

| | Grams per kWh (average over a year) |
|---|---|
| G1 | 216.04 |
| G2 | 211.83 |
| G3 | 212.03 |
| G4 | 198.60 |
| G5 | 198.71 |
| G6 | 198.94 |
| G7 | 198.58 |
| G8 | 195.63 |
| G9 | 191.36 |
| G10 | 191.82 |

Data from HOMER

# APPENDIX E: SCENARIOS EXAMINED

**TABLE E1**

SCENARIOS EXAMINED

| Scenario | Total Cost to Operate (20 years—Millions of ECD) | LUCELEC Average Profit | Total Debt (2025) | 2025 Renewable Penetration (by energy) | Description (in 2025) |
|---|---|---|---|---|---|
| 1. Diesel Fuel Only (Reference Case) | $6,173 | $44,558,035 | $39,153,303.36 | 0% | Continued diesel, new diesel installed in 2023 (12.4 MW) |
| 2. Solar, Decentralised – Debt Constrained | $5,497 | $41,389,745 | $105,045,847.52 | 18.6% | Solar (47 MW, 60% owned by LUCELEC), storage (16 MWh), and diesel |
| 3. Solar - Hybrid | $5,514 | $38,118,055 | $136,171,456.32 | 33.1% | Solar (54 MW, 80% owned by LUCELEC), storage (18 MWh), and diesel |
| 4. Solar - Centralised | $5,587 | $38,188,593 | $158,590,664.05 | 32.9% | Solar (up to 53 MW, 99% owned by LUCELEC), storage (18 MWh), and diesel |
| 5. Solar, Wind – Decentralised | $5,551 | $37,618,073 | $126,883,952.99 | 39.1% | Solar (54 MW), wind (18 MW), storage (26 MWh), and diesel |
| 6. Solar, Wind – Hybrid | $5,606 | $38,669,141 | $145,024,337.01 | 39.1% | Solar (54 MW), wind (18 MW), storage (26 MWh), and diesel |
| 7. Solar, Wind – Centralised | $5,533 | $36,081,643 | $240,656,607.17 | 38.9% | Solar (54 MW), wind (18 MW), storage (27 MWh), and diesel—Optimal rate reduction |
| 8. Solar, Geothermal – Decentralised | $5,683 | $37,852,463 | $60,573,737.09 | 69.3% | Solar (30 MW), geothermal (30 MW), storage (15 MWh), and diesel |
| 9. Solar, Geothermal – Hybrid | $5,737 | $38,678,748 | $72,039,533.24 | 69.1% | Solar (28 MW), geothermal (30 MW), storage (15 MWh), and diesel |
| 10. Solar, Geothermal – Centralised | $5,771 | $34,427,785 | $94,621,167.30 | 69.2% | Solar (27 MW), geothermal (30 MW), storage (15 MWh), and diesel |
| 11. Solar, Geothermal, Wind – Decentralised | $5,810 | $38,253,986 | $64,456,650.83 | 75.3% | Solar (30 MW), wind (12 MW), geothermal (30 MW), storage (12 MWh), and diesel |
| 12. Solar, Geothermal, Wind, – Hybrid | $5,822 | $39,425,126 | $64,556,062.65 | 75.4% | Solar (24 MW), wind (12 MW), geothermal (30 MW), storage (19 MWh), and diesel |
| 13. Solar, Geothermal, Wind – Centralised | $5,746 | $34,171,419 | $129,945,859.91 | 75.3% | Solar (23 MW), wind (12 MW), geothermal (30 MW), storage (19 MWh), and diesel |
| 14. Thermal IPP | $6,010 | $39,223,989 | $299,255,995.09 | 0% | Natural gas (40 MW) from retrofits and diesel (46.3 MW w/new 12.4 MW in 2023) |

# APPENDIX F: DETAILS ON SELECTED SCENARIOS

**TABLE F1**

INSTALLED CAPACITY FOR SCENARIO 1—FFOS

| Year | Diesel Installed Capacity (MW) | Solar Installed Capacity (MW) | Wind Installed Capacity (MW) | Geothermal Installed Capacity (MW) | Storage Installed Capacity (MWh) |
|---|---|---|---|---|---|
| 2015 | 86.2 | 0 | 0 | 0 | 0 |
| 2016 | 86.2 | 0 | 0 | 0 | 0 |
| 2017 | 86.2 | 0 | 0 | 0 | 0 |
| 2019 | 86.2 | 0 | 0 | 0 | 0 |
| 2024 | 86.2 | 0 | 0 | 0 | 0 |
| 2035 | 86.2 | 0 | 0 | 0 | 0 |

**TABLE F2**

RESERVES FOR SCENARIO 1—FFOS

| Year | Diesel Installed Capacity (MW) | Total Installed Capacity (MW) | Average Hourly Operating Reserve (MW) |
|---|---|---|---|
| 2015 | 86.2 | 86.2 | 8.6 |
| 2016 | 86.2 | 86.2 | 8.7 |
| 2017 | 86.2 | 86.2 | 9.1 |
| 2019 | 86.2 | 86.2 | 9.1 |
| 2024 | 86.2 | 86.2 | 8.7 |
| 2035 | 86.2 | 86.2 | 8.4 |

**TABLE F3**

INSTALLED CAPACITY FOR SCENARIO 2—SOLAR DECENTRALISED

| Year | Diesel Installed Capacity (MW) | Utility Solar Installed Capacity (MW) | Wind Installed Capacity (MW) | Geothermal Installed Capacity (MW) | Storage Installed Capacity (MWh) |
|---|---|---|---|---|---|
| 2015 | 86.2 | 0 | 0 | 0 | 0 |
| 2016 | 86.2 | 0 | 0 | 0 | 0 |
| 2017 | 67.8 | 1.0 | 0 | 0 | 0 |
| 2019 | 67.8 | 24.8 | 0 | 0 | 7.0 |
| 2024 | 67.8 | 32.4 | 0 | 0 | 15.0 |
| 2035 | 67.8 | 81.7 | 0 | 0 | 43.0 |

**TABLE F4**

RESERVES FOR SCENARIO 2 – SOLAR DECENTRALISED

| Year | Diesel Installed Capacity (MW) | Total Installed Capacity (MW) | Average Hourly Operating Reserve (MW) |
|---|---|---|---|
| 2015 | 86.2 | 86.2 | 8.6 |
| 2016 | 86.2 | 88.1 | 8.7 |
| 2017 | 67.8 | 71.5 | 9.2 |
| 2019 | 67.8 | 97.9 | 11.4 |
| 2024 | 67.8 | 116.1 | 15.6 |
| 2035 | 67.8 | 172.4 | 30.6 |

**TABLE F5**

INSTALLED CAPACITY FOR SCENARIO 7—SOLAR + WIND WITH LOW DG

| Year | Diesel Installed Capacity (MW) | Utility Solar Installed Capacity (MW) | Wind Installed Capacity (MW) | Geothermal Installed Capacity (MW) | Storage Installed Capacity (MWh) |
|---|---|---|---|---|---|
| 2015 | 86.2 | 0 | 0 | 0 | 0 |
| 2016 | 86.2 | 0 | 0 | 0 | 0 |
| 2017 | 67.8 | 1.0 | 0 | 0 | 0 |
| 2019 | 67.8 | 26.7 | 12.0 | 0 | 11.0 |
| 2024 | 67.8 | 50.2 | 18.0 | 0 | 25.0 |
| 2035 | 67.8 | 86.8 | 18.0 | 0 | 45.0 |

**TABLE F6**

RESERVES FOR SCENARIO 7 – SOLAR + WIND WITH LOW DG

| Year | Diesel Installed Capacity (MW) | Total Installed Capacity (MW) | Average Hourly Operating Reserve (MW) |
|---|---|---|---|
| 2015 | 86.2 | 86.2 | 8.6 |
| 2016 | 86.2 | 86.2 | 8.7 |
| 2017 | 67.8 | 68.9 | 8.9 |
| 2019 | 67.8 | 106.7 | 13.8 |
| 2024 | 67.8 | 136.5 | 22.1 |
| 2035 | 67.8 | 173.7 | 32.2 |

**TABLE F7**

INSTALLED CAPACITY FOR SCENARIO 13—SOLAR + WIND + GEOTHERMAL WITH LOW DG

| Year | Diesel Installed Capacity (MW) | Utility Solar Installed Capacity (MW) | Wind Installed Capacity (MW) | Geothermal Installed Capacity (MW) | Storage Installed Capacity (MWh) |
|---|---|---|---|---|---|
| 2015 | 86.2 | 0 | 0 | 0 | 0 |
| 2016 | 86.2 | 0 | 0 | 0 | 0 |
| 2017 | 67.8 | 1.0 | 0 | 0 | 0 |
| 2019 | 67.8 | 14.5 | 12.0 | 0 | 0 |
| 2024 | 67.8 | 19.4 | 12.0 | 30.0 | 17.0 |
| 2035 | 67.8 | 48.8 | 18.0 | 30.0 | 40.0 |

**TABLE F8**

RESERVES FOR SCENARIO 13 – SOLAR + WIND + GEOTHERMAL WITH LOW DG

| Year | Diesel Installed Capacity (MW) | Total Installed Capacity (MW) | Average Hourly Operating Reserve (MW) |
|---|---|---|---|
| 2015 | 86.2 | 86.2 | 8.6 |
| 2016 | 86.2 | 86.2 | 8.7 |
| 2017 | 67.8 | 68.9 | 8.9 |
| 2019 | 67.8 | 94.5 | 11.4 |
| 2024 | 67.8 | 129.6 | 14.0 |
| 2035 | 67.8 | 165.7 | 25.3 |

## APPENDIX G: DISPATCH OF CURRENT AND FUTURE RESOURCES

**FIGURE G1**

2017 SOLAR/HIGH DG DISPATCH VISUALISATION

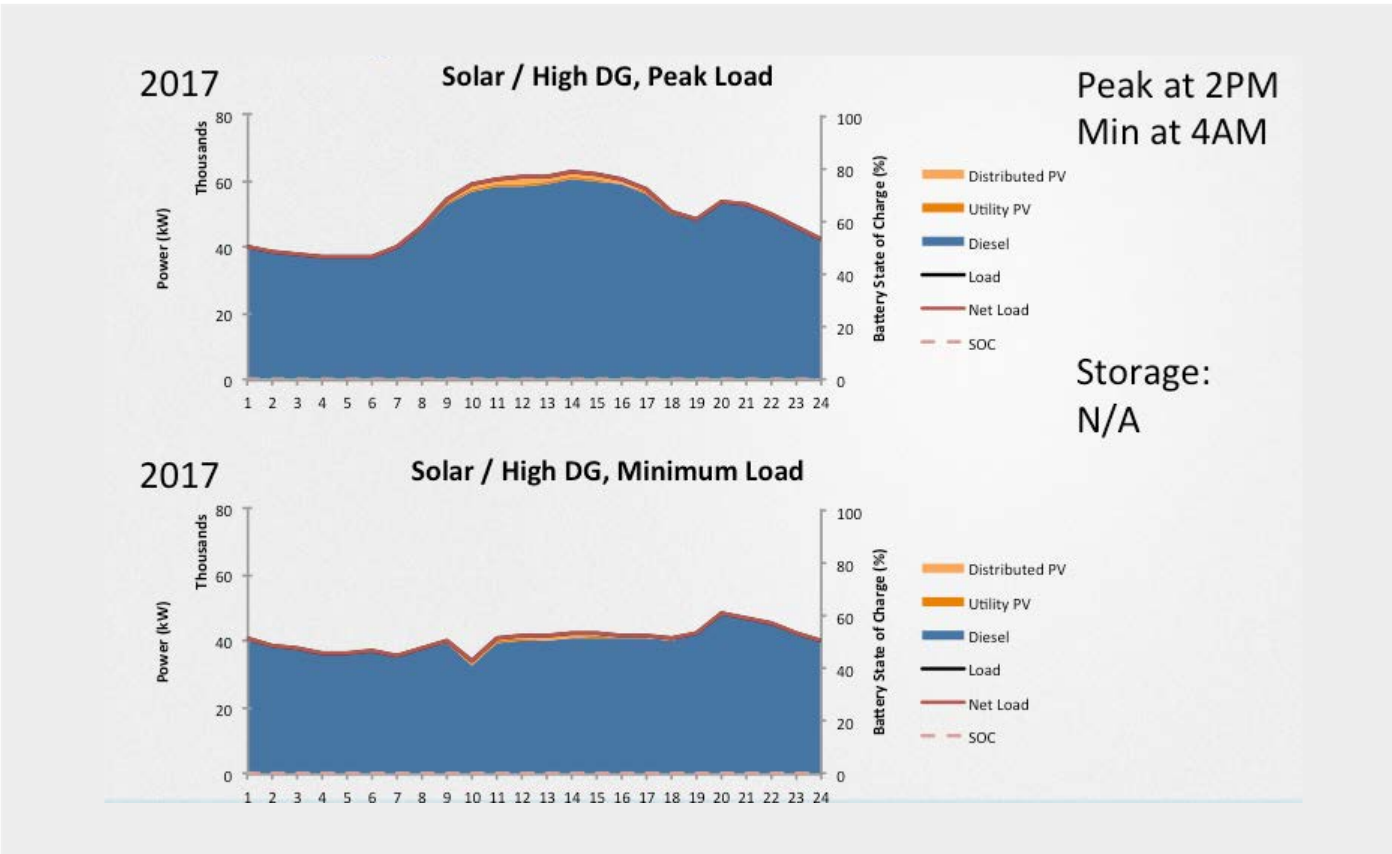


**FIGURE G2**
2024 SOLAR/HIGH DG DISPATCH VISUALISATION

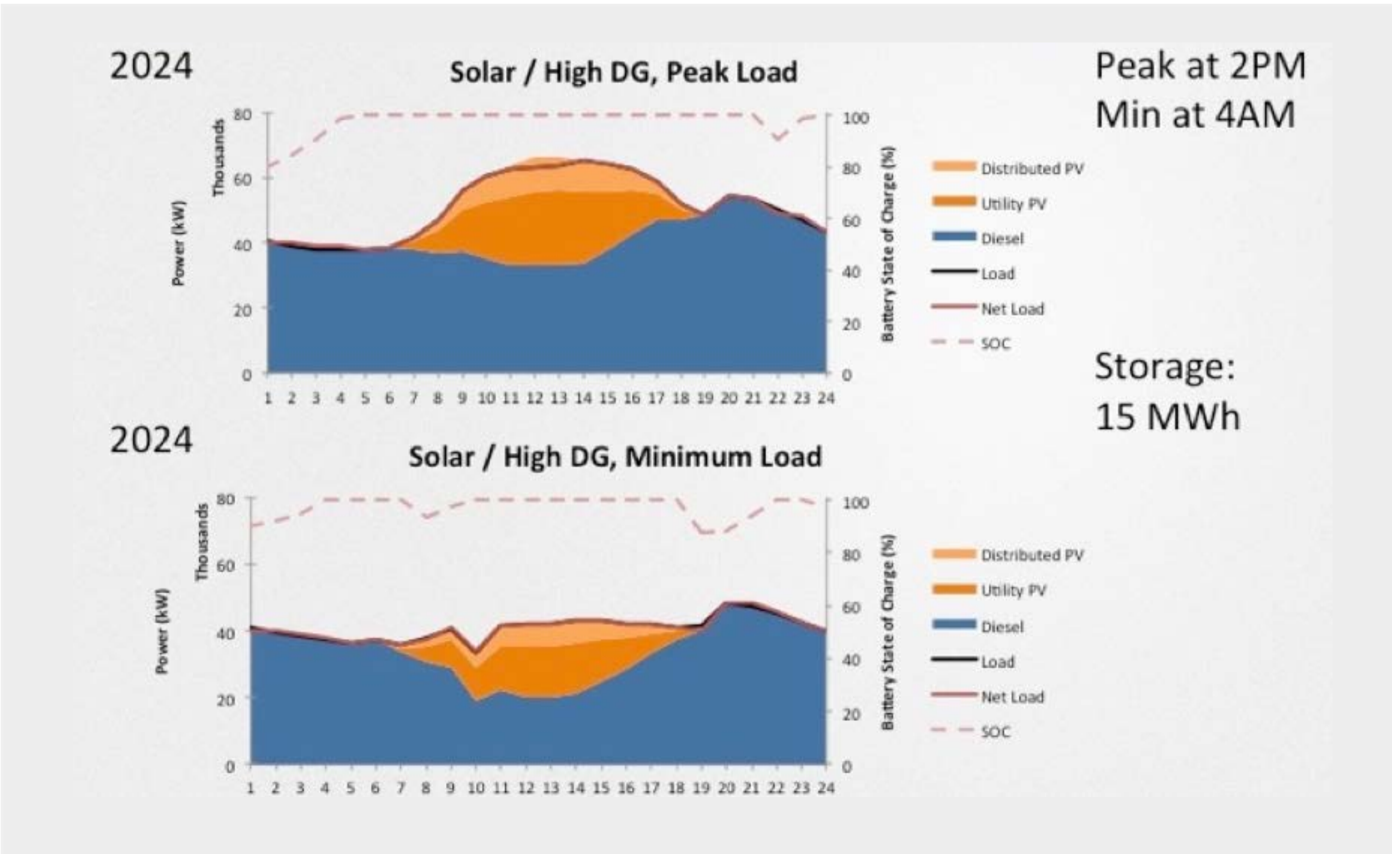


**FIGURE G3**
2035 SOLAR/HIGH DG DISPATCH VISUALISATION

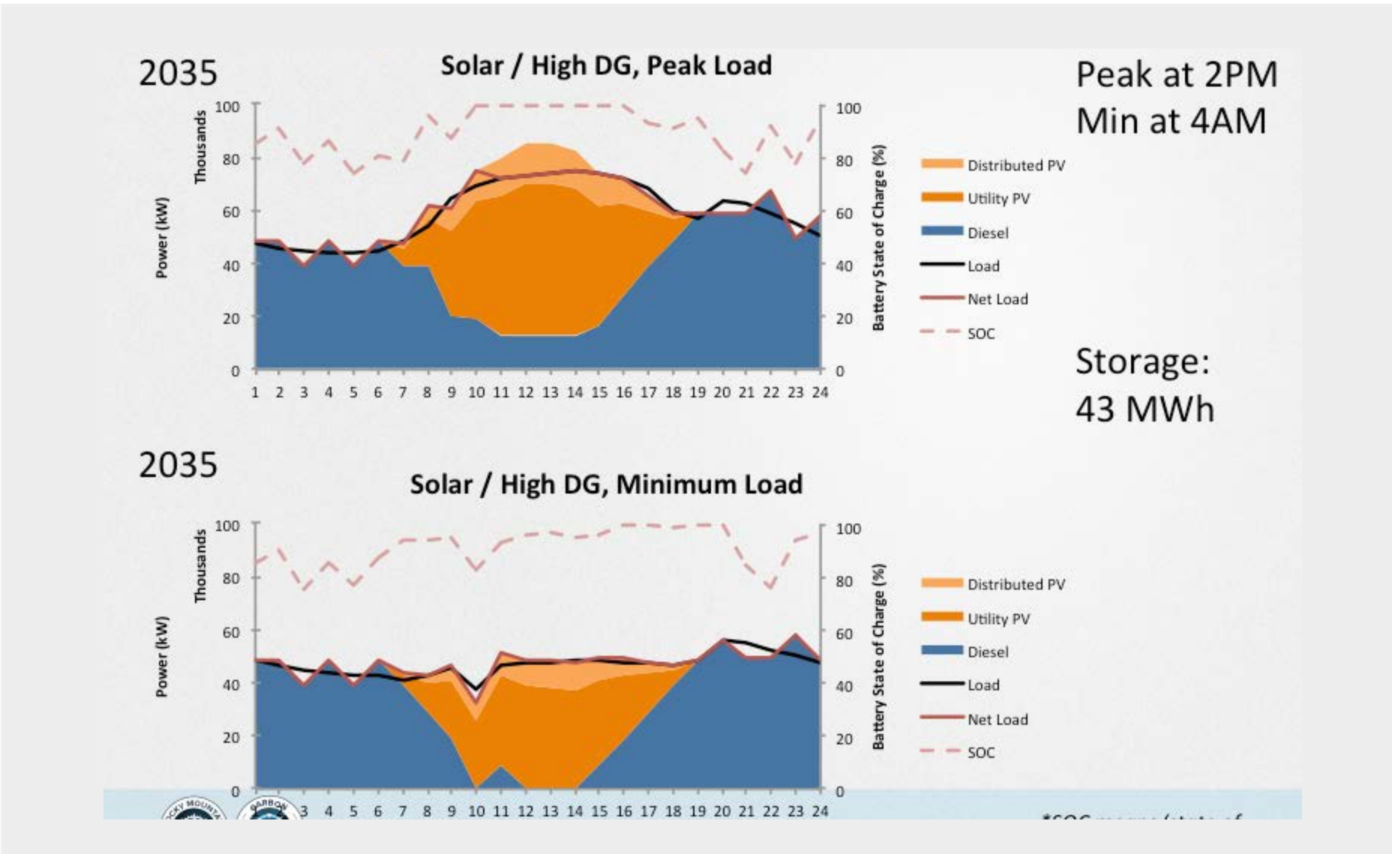


**FIGURE G4**

2024 SOLAR+WIND/HIGH DG DISPATCH VISUALISATION

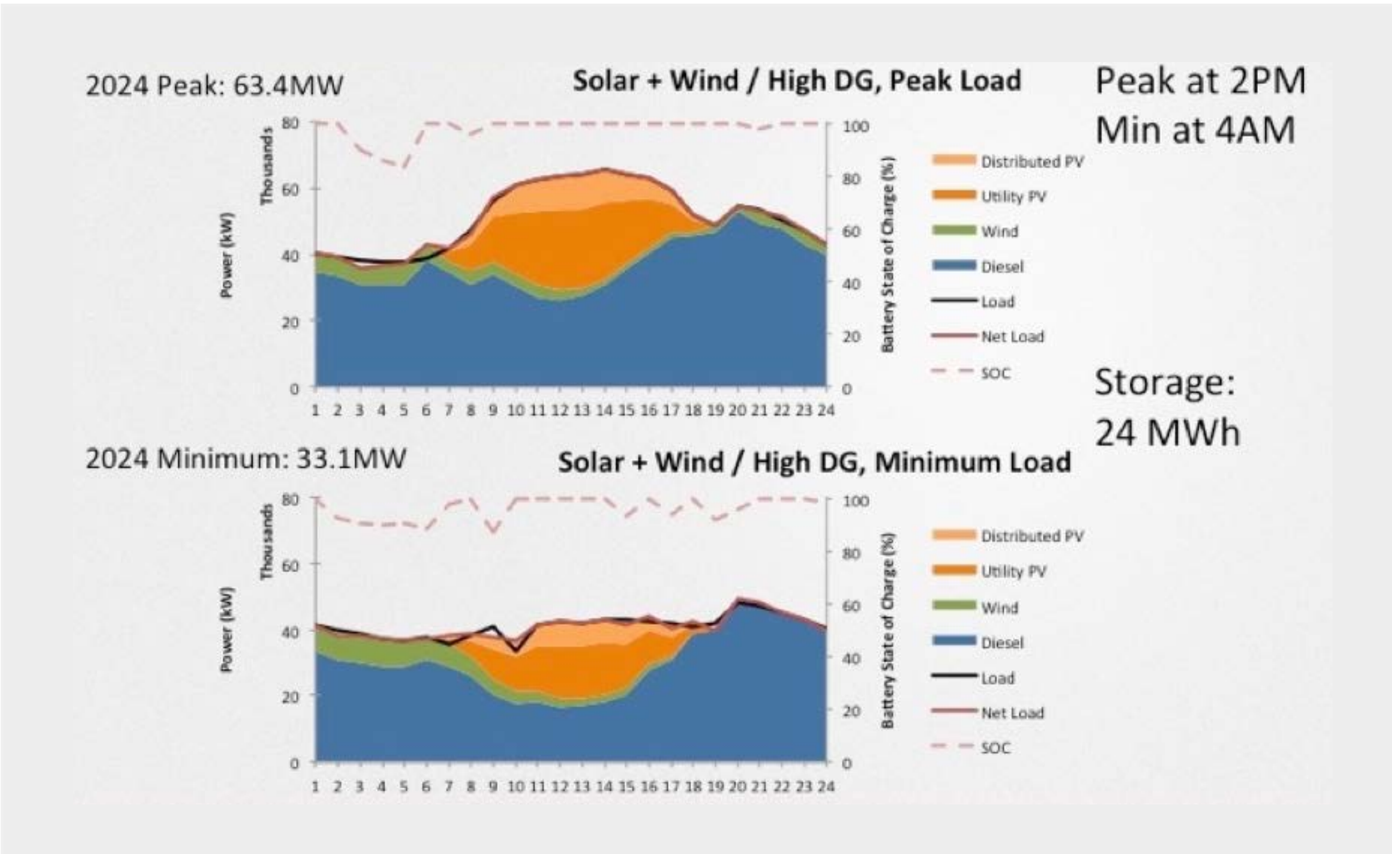


**FIGURE G5**
2024 SOLAR+GEO/LOW DG DISPATCH VISUALISATION

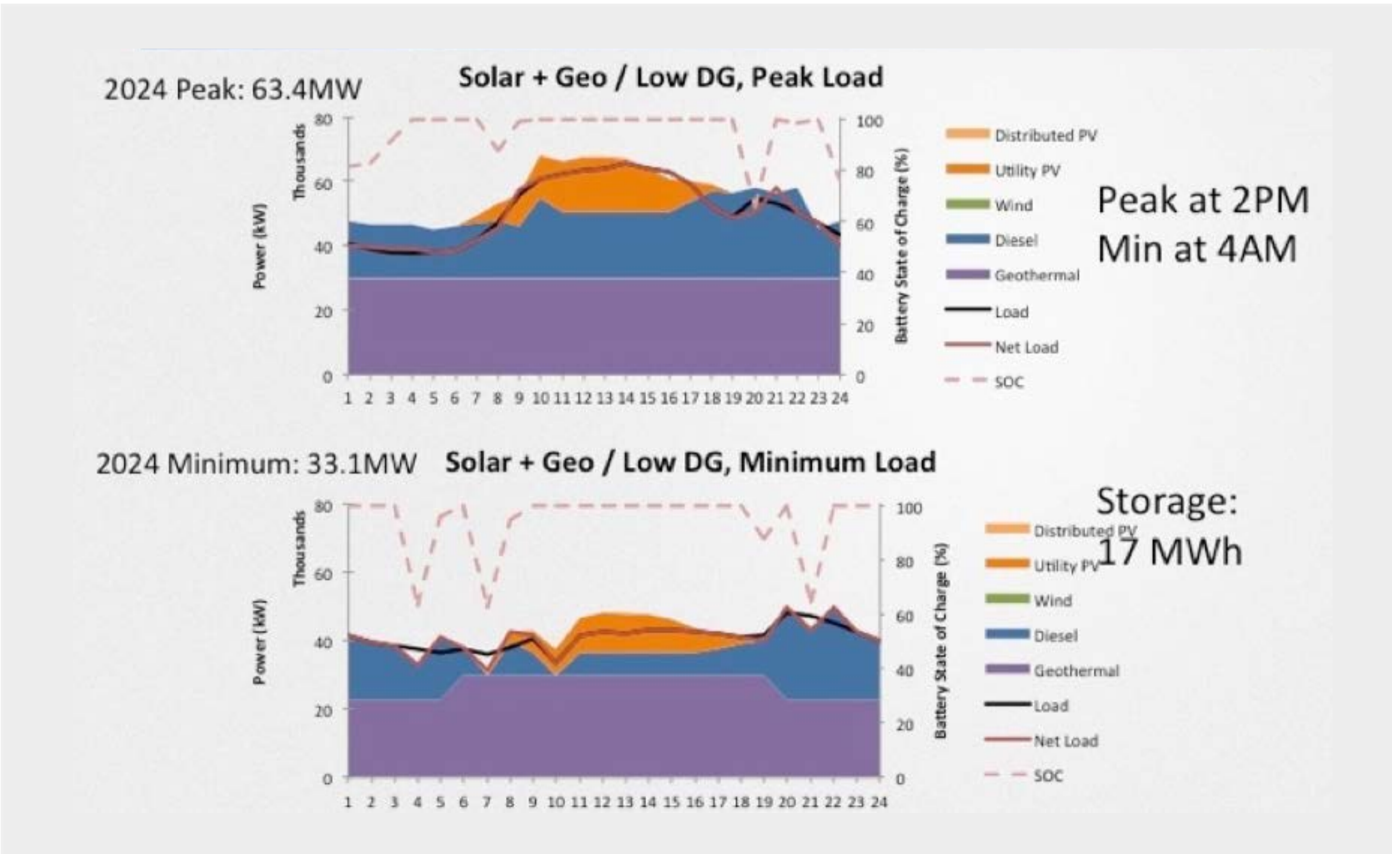
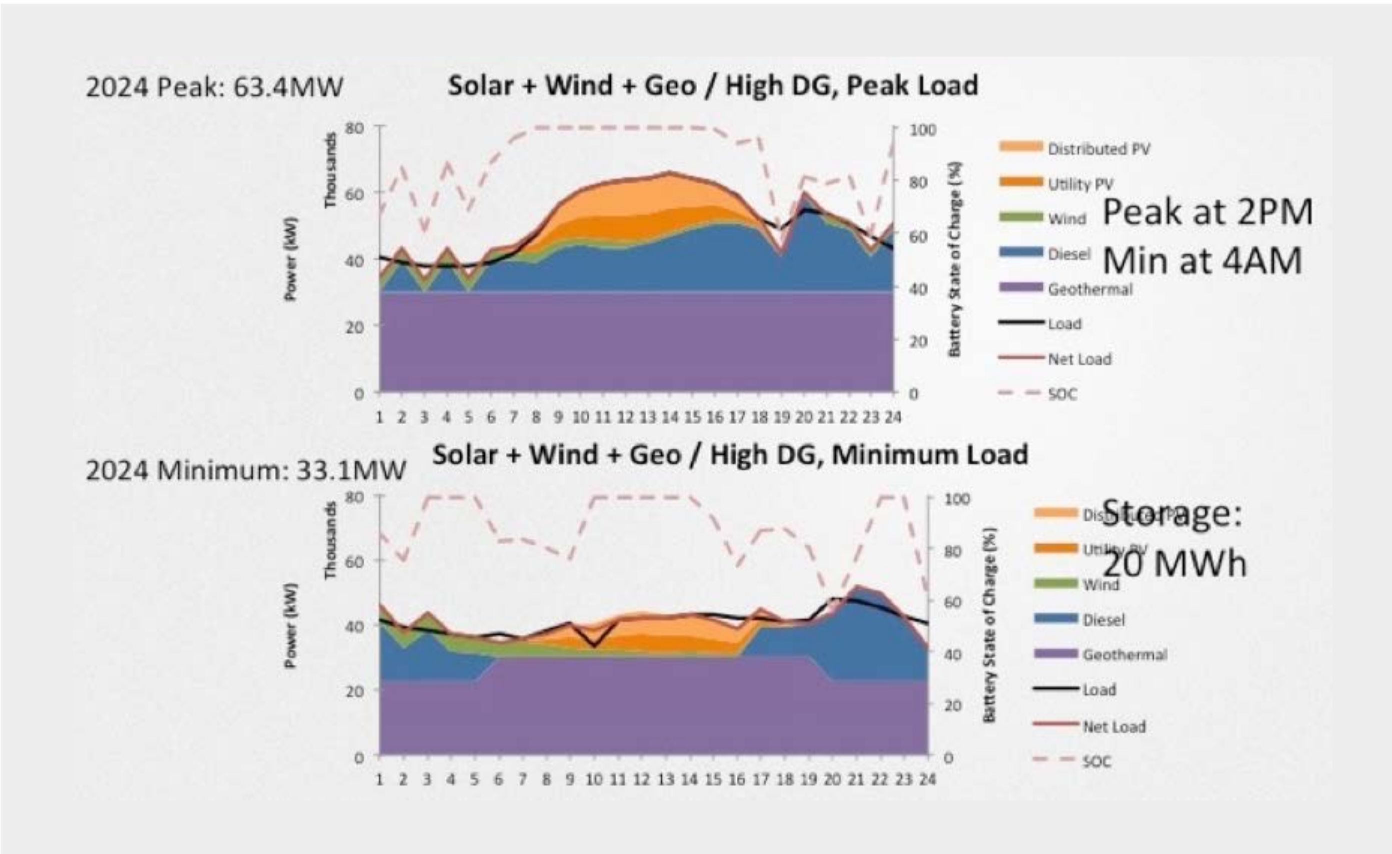


**FIGURE G6**

2024 SOLAR+WIND+GEO/HIGH DG DISPATCH VISUALISATION



# APPENDIX H: EMISSIONS

**FIGURE H1**

A VARIETY OF SCENARIOS MEET THE RENEWABLE PENETRATION TARGET (AS EXPRESSED IN ENERGY) IN 2025

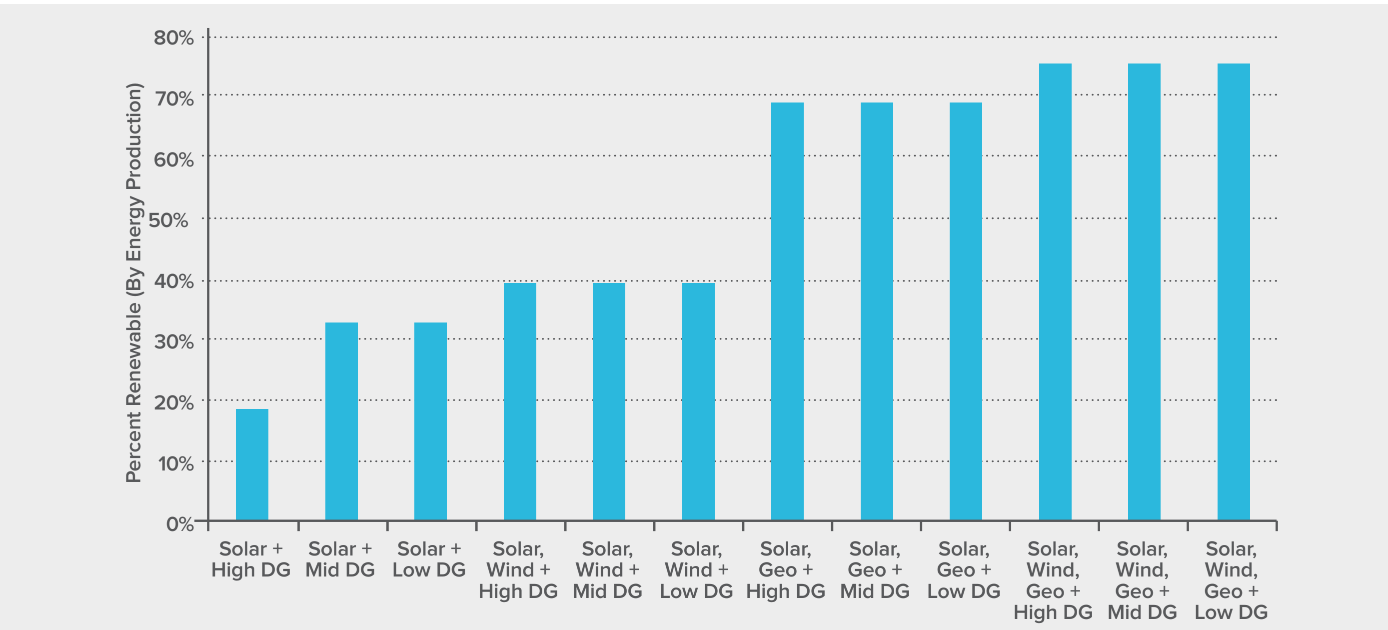
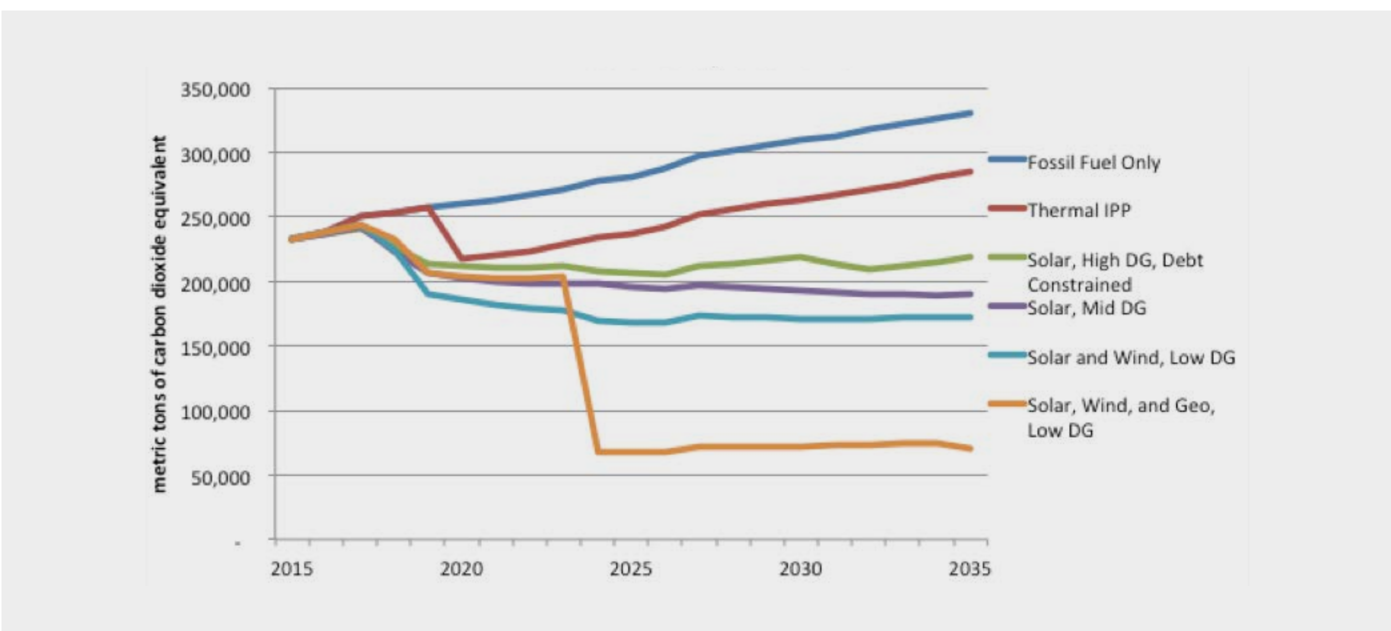



**FIGURE H2**

EMISSIONS BY SCENARIO BY YEAR



# APPENDIX I: UTILITY RATE STRUCTURES

## CURRENT RATE STRUCTURES:

**FIGURE I1**
2016 RATE COMPONENTS


Time-of-Use Charges

- Charges customers more for consumption at peak hours
- Incentivises flattening of system load profile which can reduce the need to invest in new capacity

Block Tariffs, Rising Block Tariffs

- Tiered pricing structure where higher-usage customers pay an increasing marginal rate
- Encourages energy efficiency and allows low-usage customers to benefit from lower rates

Demand Charges

- The cost to supply high-demand customers is greater
- Better matches cost to revenue
- Incentivises flattening of load profile, which can reduce the need to upgrade distribution lines

Rate-of-Return Regulation

- A form of price-setting regulation where governments determine the fair price that a monopoly is allowed to charge; this aims to protect the customers while ensuring the utility makes adequate returns to cover its cost and earn a fair return

- Calculated based on operating costs
- If costs are reduced, customers still pay the same

Price-Cap Regulation

- A form of economic regulation specific to the utility industry in the United Kingdom; sets a cap on the price that the utility provider can charge; the cap is set according to several economic factors, such as the price-cap index, expected efficiency savings, and inflation
- It protects consumers while ensuring that the utility remains profitable
- Often used where there are multiple utilities

Revenue-Cap Regulation

- Seeks to limit the amount of total revenue received by a company operating which holds monopoly status in the industry; like price-cap regulation, revenue-cap regulation is determined according to inflation, the consumer price index (CPI), and the efficiency savings factor
- Designed to incentivise regulated monopolies to increase their efficiency

Objectives of an Alternative Rate Design—implications for EE

- Regardless of the amount of kWh sold, LUCELEC is assured of its revenue
- There is strong financial incentive for the utility to reduce its costs of generation and distribution as it is allowed to benefit fully from the savings
- Utilities might sacrifice service and/or reliability in an effort to cut costs so the NURC should establish minimum performance criteria (such as maximum duration and incidence of power outages)

Rate Design Variations

- Uniform (simplicity)
- Lifeline (affordability)
- Locational (congestion relief)
- Interruptible or curtailment (load management)
- Time-of-use (efficiency)
- Real-time (demand response)
- Critical peak (load management)
- Net billing (distributed generation)

# APPENDIX J: LUCELEC FINANCIAL INFORMATION

Calculating the cost to generate using sales (per LUCELEC and Castalia methodology). Using kWh generated (seemingly a more accurate metric) results in EC$0.54 or US$0.20 per kWh.

**FIGUREJ1**

LUCELEC PROVIDES POWER WHILE MAKING REASONABLE PROFIT (2014 COST BREAKDOWN)

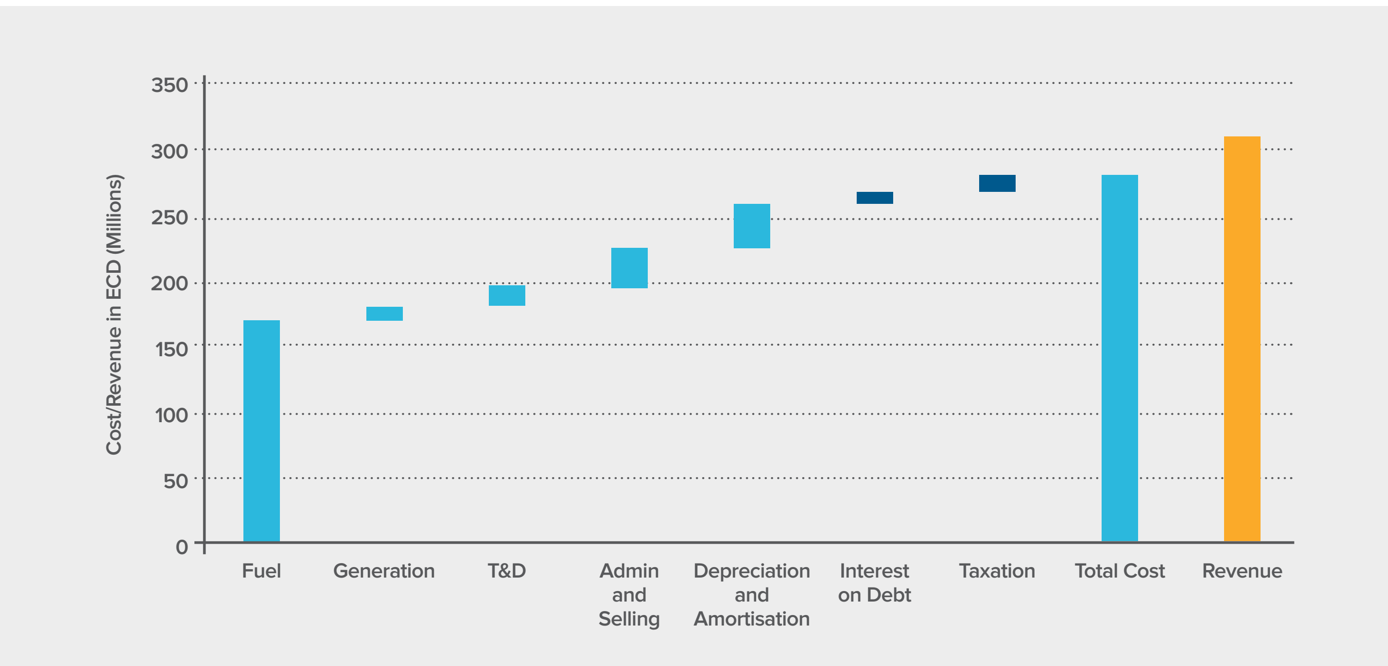


**FIGURE J2**

LUCELEC HISTORICAL COST STRUCTURE AND REVENUE

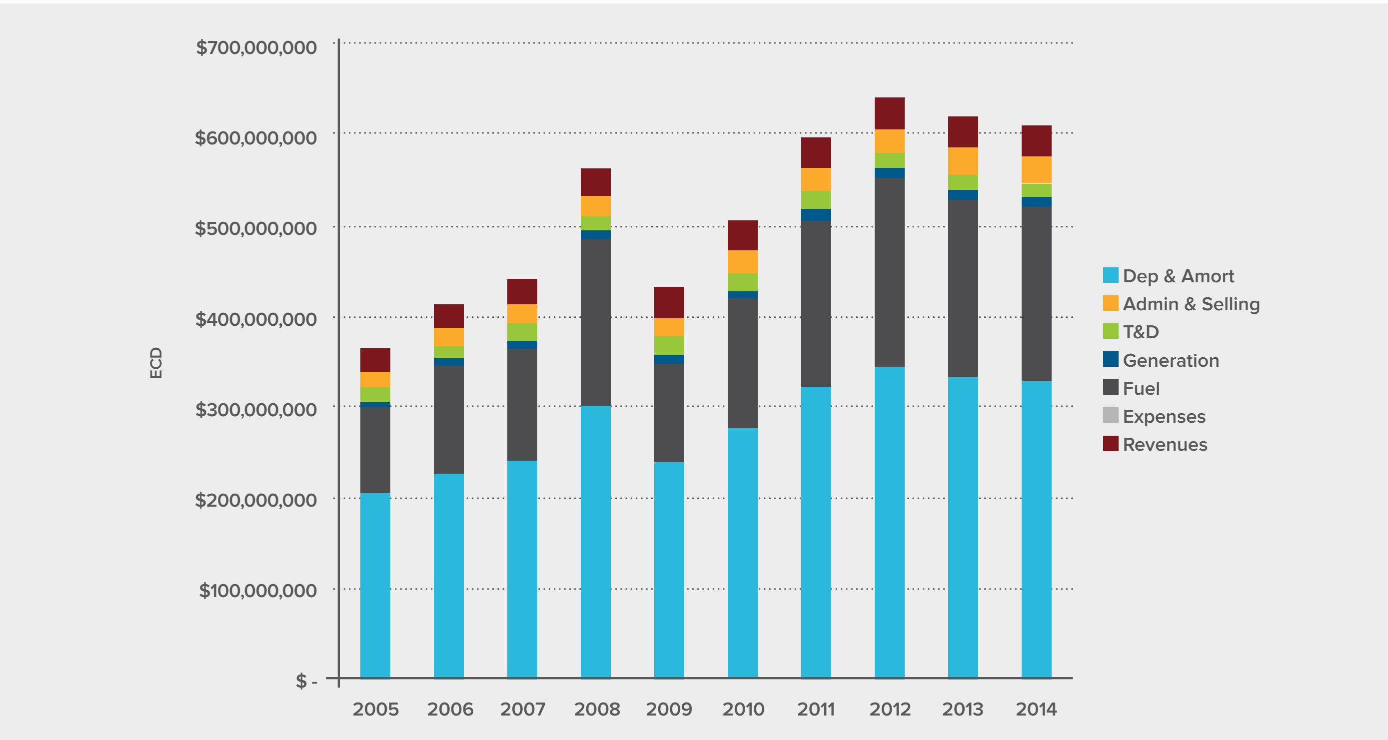



**FIGURE J3**

PRO-FORMA: DIESEL-FUEL-ONLY SCENARIO

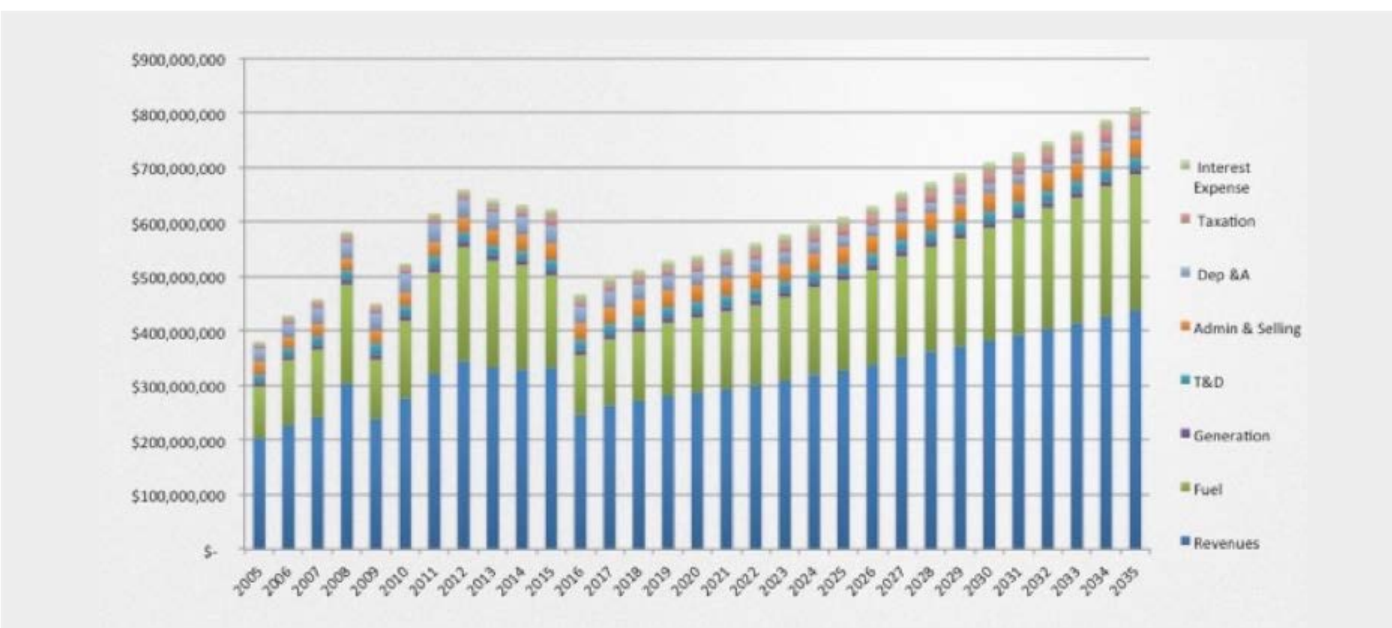


**FIGURE J4**
PROFITABILITY OF THE SCENARIOS

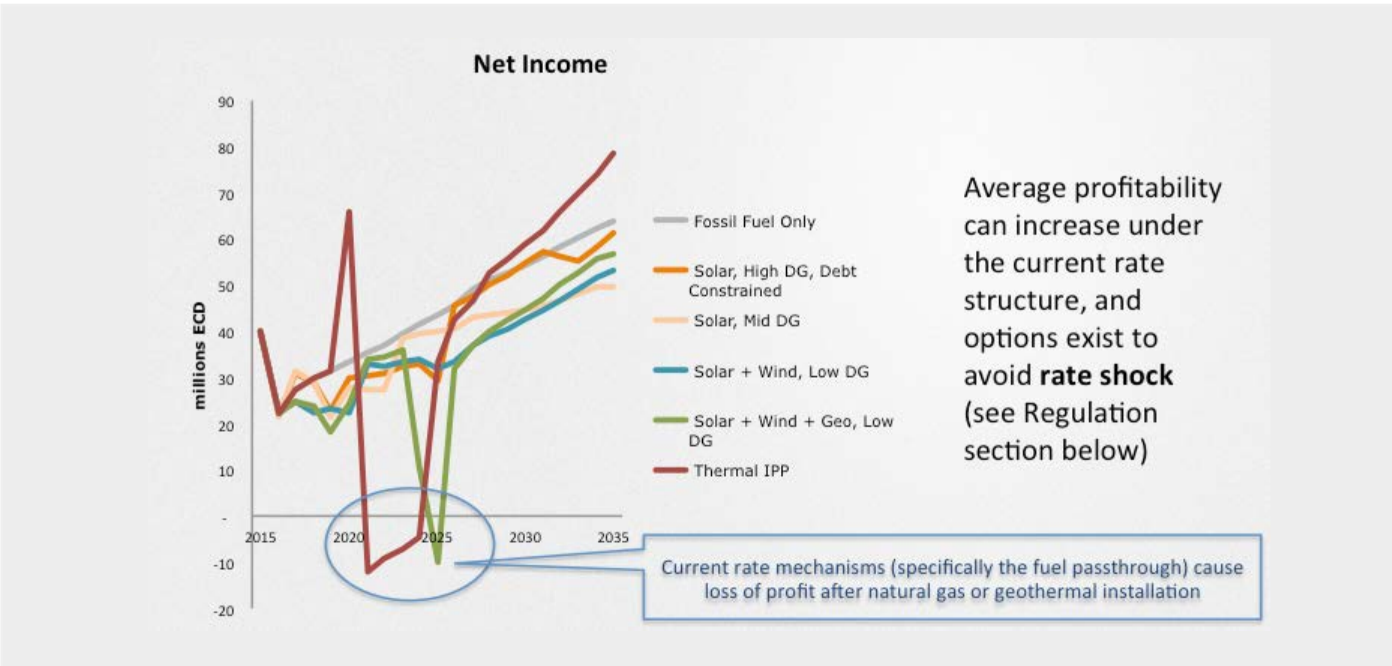



**FIGURE J5**
LUCELEC DEBT BURDEN OVER TIME

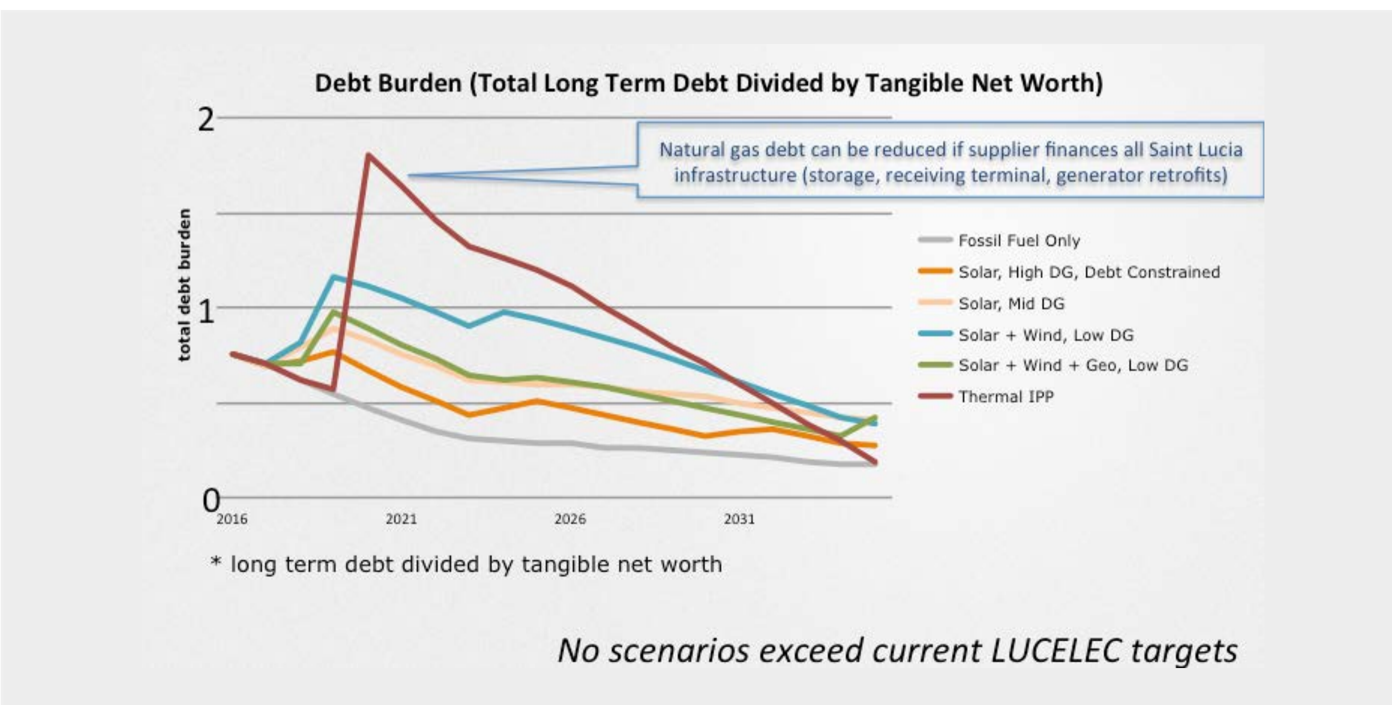
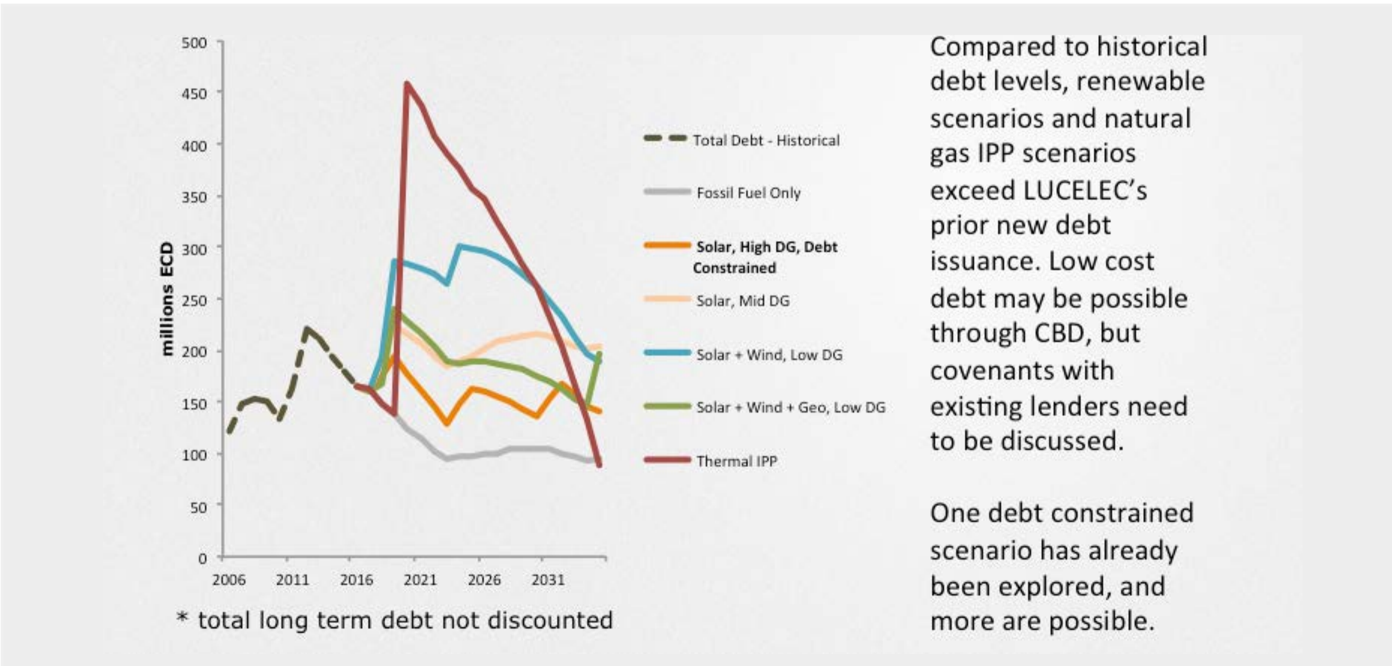


**FIGURE J6**

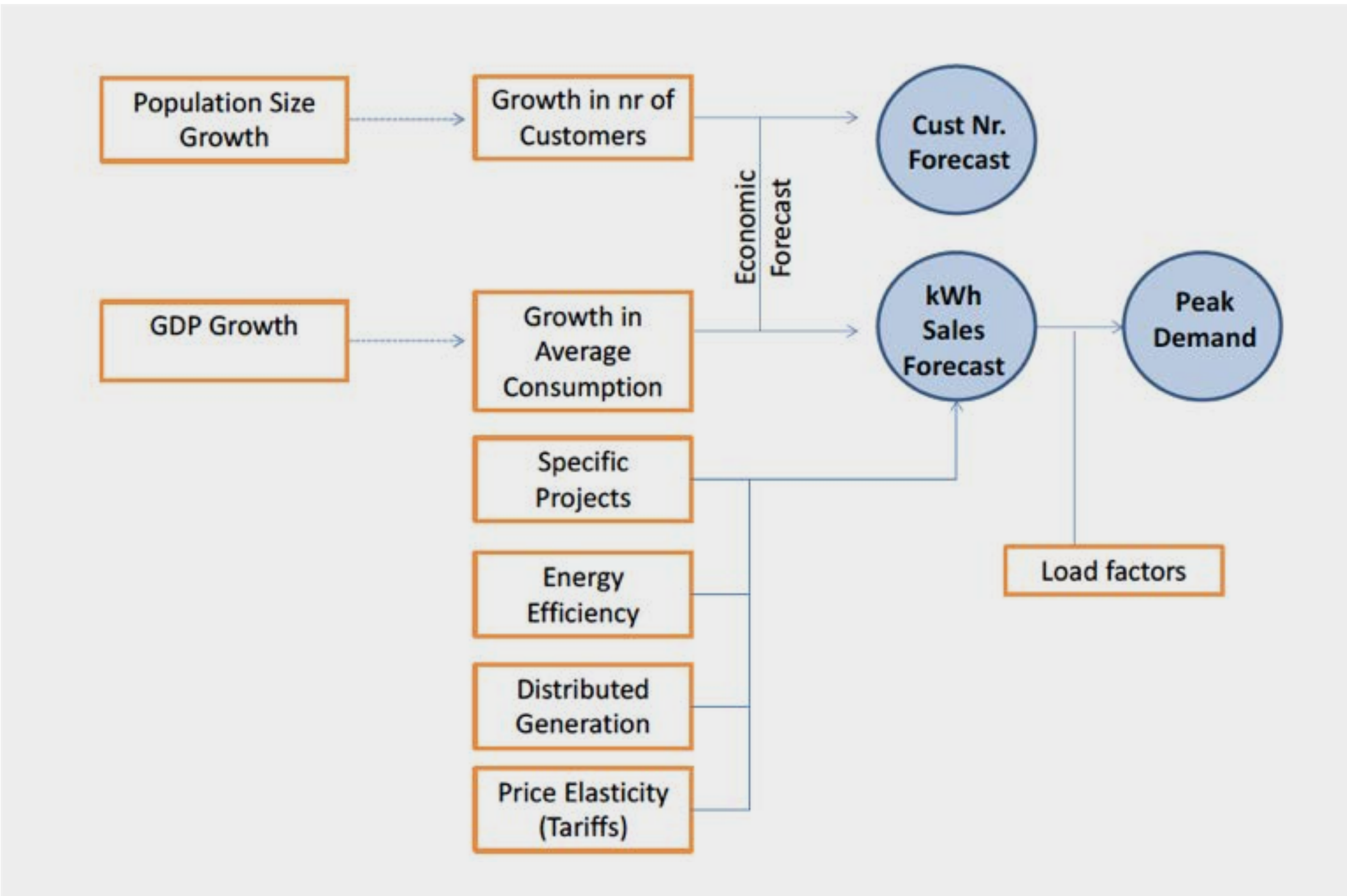
DEBT MAY LIMIT THE POTENTIAL FOR SIGNIFICANT CAPACITY EXPANSION



## APPENDIX K: LOAD FORECAST METHODOLOGY

**FIGUREK1**

OVERVIEW OF LOAD FORECAST METHODOLOGY




- Annual and monthly historical sales by customer category provided by LUCELEC
- DNV GL conducted a site visit during the week of January 27, 2016, to interview LUCELEC, Invest Saint Lucia, and future hotels and commercial customers for special projects
- Macro-socioeconomic data from Eastern Caribbean Central Bank and World Bank
- Energy efficiency profiles (following Figures) based on Barbados demand side management (DSM) study
- Determinations of peak demand assume a load factor of 71.1 per cent (inclusive of losses, which were 8.7 per cent in 2015)

**FIGURE K2**

OVERALL SYSTEM PROFILE

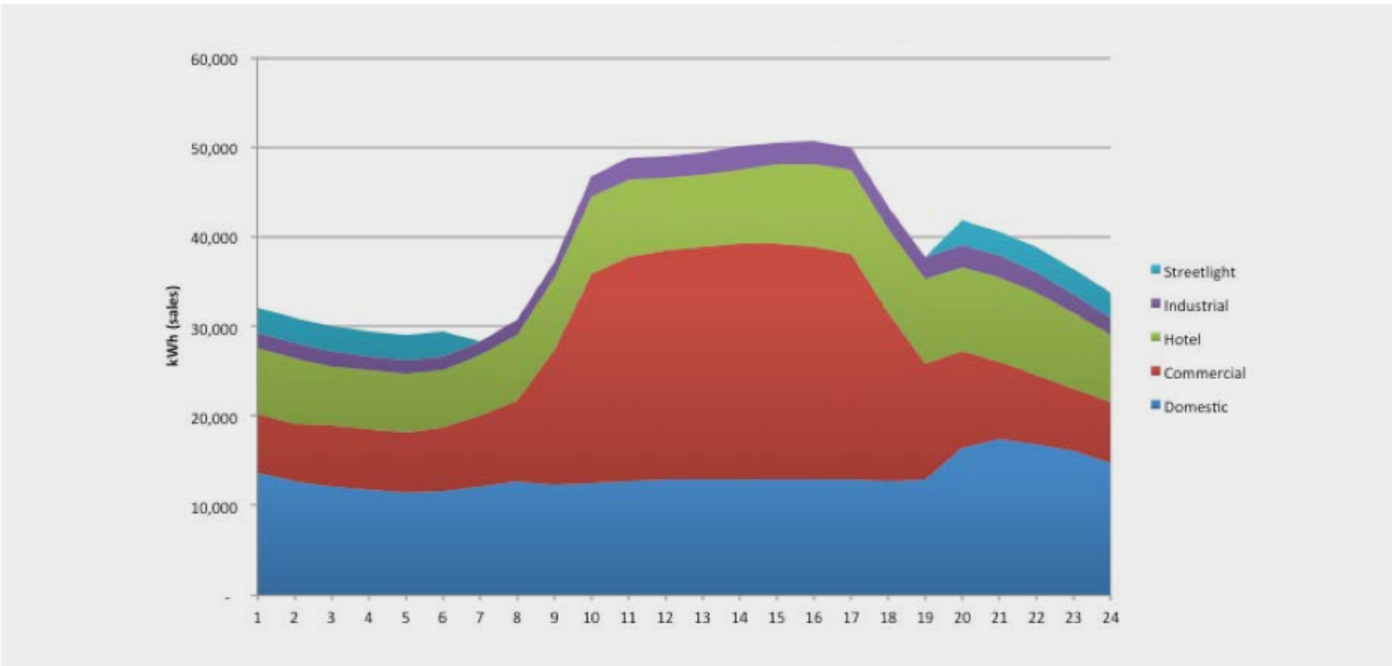



**FIGURE K3**

LOAD FORECAST—BASE SCENARIO WITHOUT EE

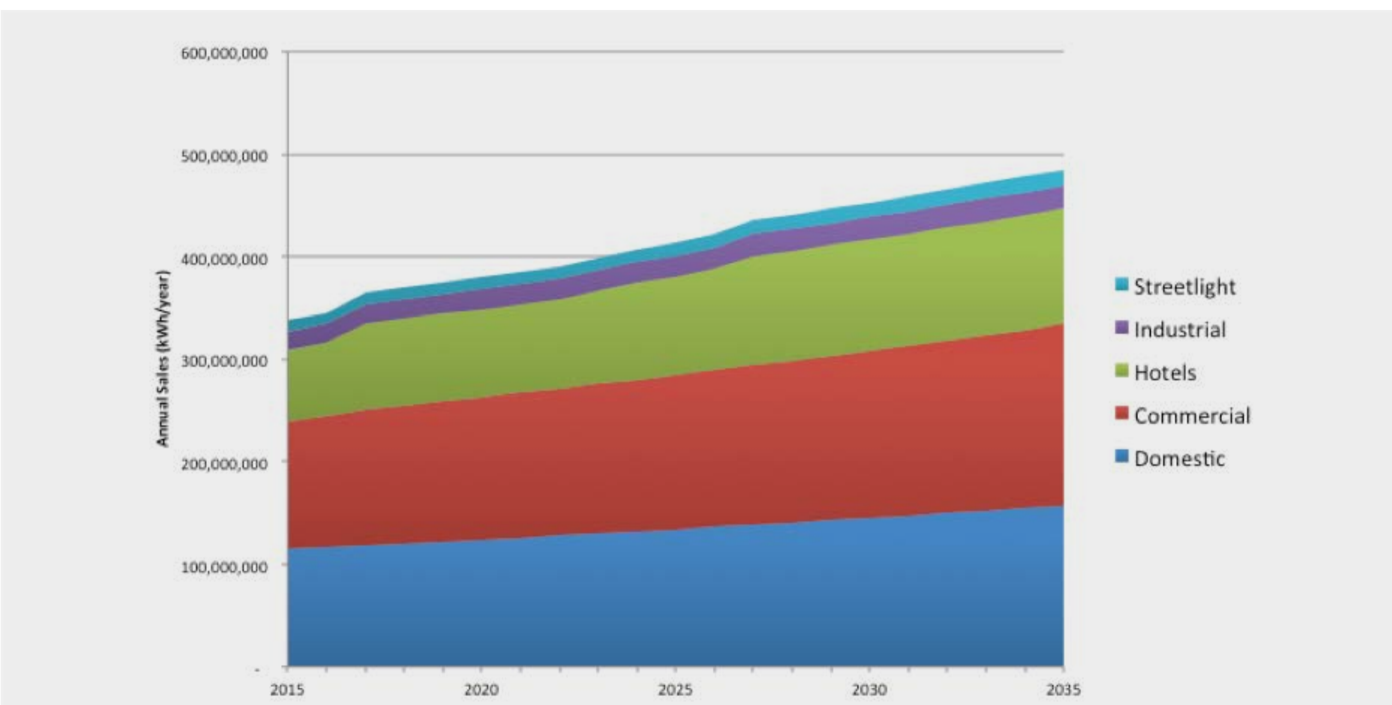


**FIGURE K4**

LOAD FORECAST—BASE SCENARIO WITH EE

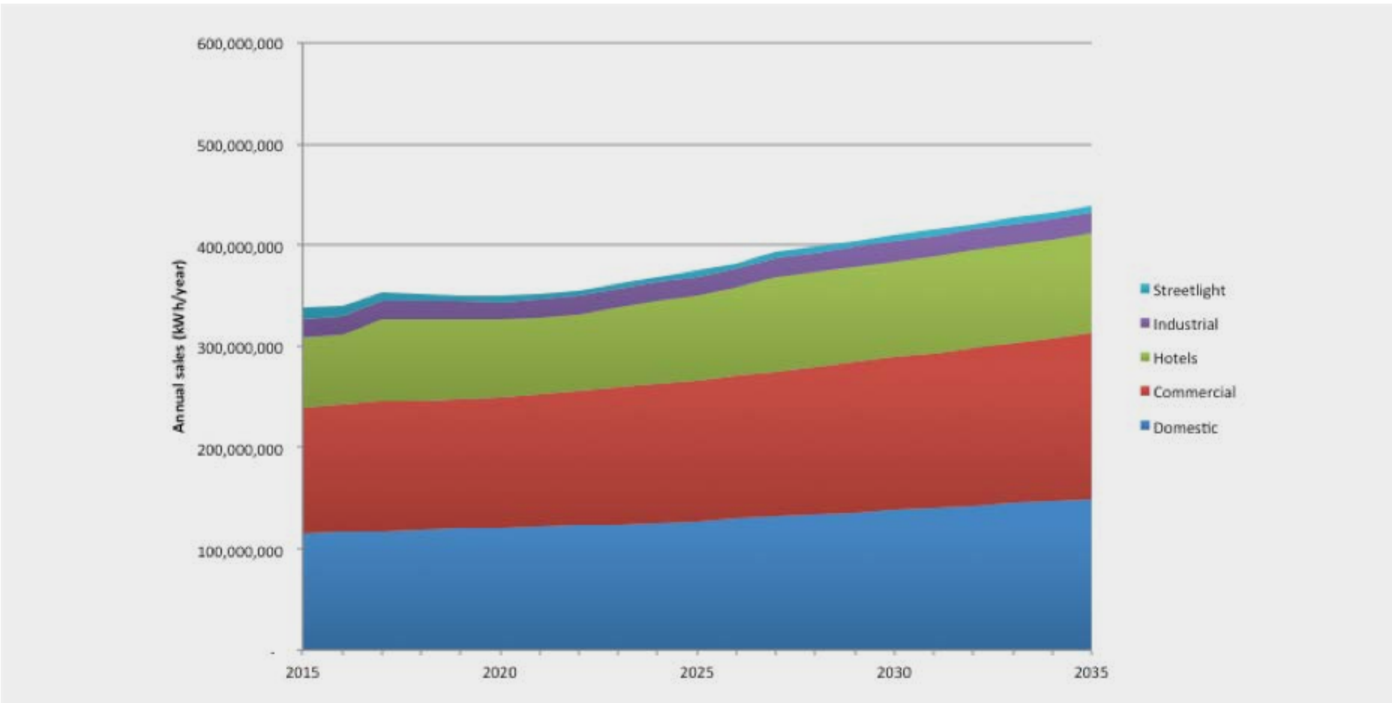
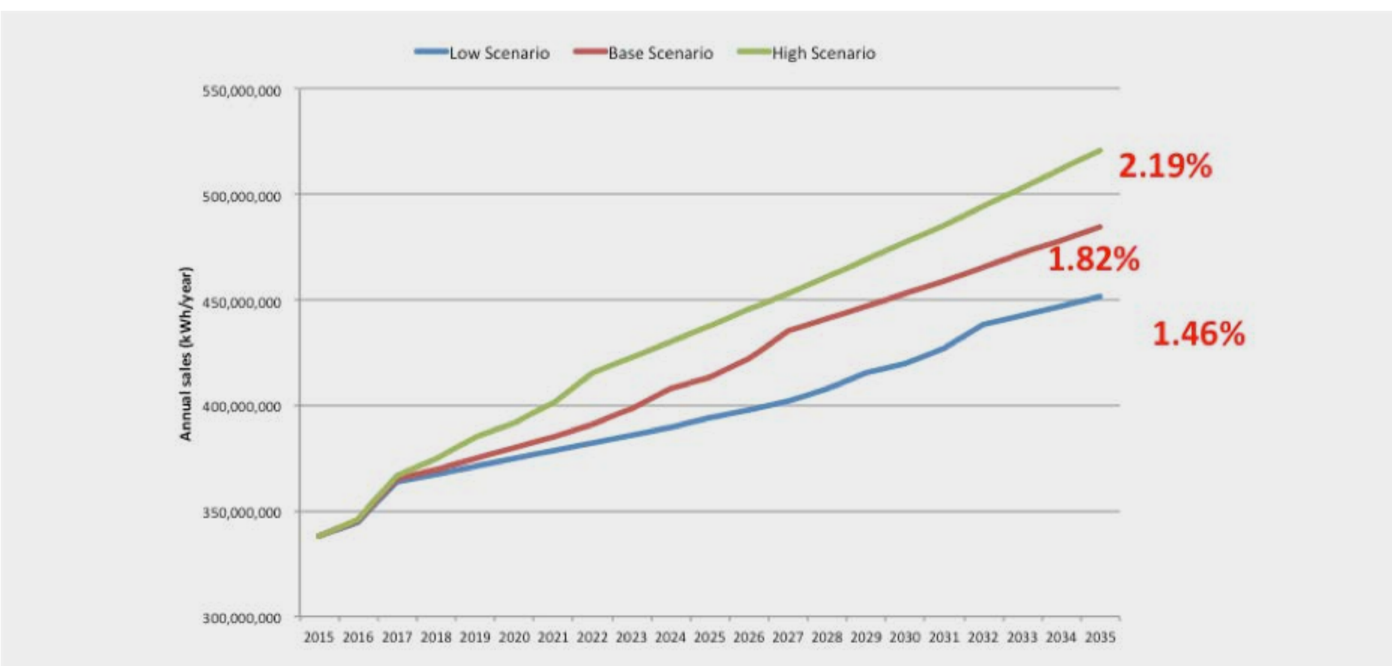



**FIGURE K5**

LOAD FORECAST—SALES BY SCENARIO WITHOUT EE



## APPENDIX L: ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT DETAILS

**TABLE L1**

SAINT LUCIA DSM PROGRAM COST PROJECTIONS FOR 2017–2035

| | INCENTIVE COSTS | | | | | PROGRAM COSTS | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Residential | Commercial | Hotel | Streetlighting | Subtotal | Admin | Marketing | Subtotal | TOTALS | TOTALS w/o Streetlighting |
| 1 | $7,606,795 | $2,250,567 | $935,315 | $6,598,550 | $17,391,228 | $809,451 | $809,451 | $1,618,902 | $19,010,129 | $12,411,580 |
| 2 | $7,606,795 | $2,250,567 | $935,315 | $6,598,550 | $17,391,228 | $809,451 | $809,451 | $1,618,902 | $19,010,129 | $12,411,580 |
| 3 | $7,606,795 | $2,250,567 | $935,315 | $6,598,550 | $17,391,228 | $809,451 | $809,451 | $1,618,902 | $19,010,129 | $12,411,580 |
| 4 | $6,847,246 | $712,370 | $442,602 | $6,598,550 | $14,600,768 | $600,166 | $600,166 | $1,200,333 | $15,801,101 | $9,202,551 |
| 5 | $6,847,246 | $712,370 | $442,602 | $ - | $8,002,218 | $600,166 | $600,166 | $1,200,333 | $9,202,551 | $9,202,551 |
| 6 | $3,864,996 | $351,820 | $357,102 | $ - | $4,573,918 | $343,044 | $343,044 | $686,088 | $5,260,006 | $5,260,006 |
| 7 | $3,864,996 | $351,820 | $357,102 | $ - | $4,573,918 | $343,044 | $343,044 | $686,088 | $5,260,006 | $5,260,006 |
| 8 | $3,864,996 | $351,820 | $357,102 | $ - | $4,573,918 | $343,044 | $343,044 | $686,088 | $5,260,006 | $5,260,006 |
| 9 | $3,864,996 | $351,820 | $357,102 | $ - | $4,573,918 | $343,044 | $343,044 | $686,088 | $5,260,006 | $5,260,006 |
| 10 | $3,864,996 | $351,820 | $357,102 | $ - | $4,573,918 | $343,044 | $343,044 | $686,088 | $5,260,006 | $5,260,006 |
| 11 | $1,455,338 | $351,820 | $357,102 | $ - | $2,164,260 | $162,320 | $162,320 | $324,639 | $2,488,899 | $2,488,899 |
| 12 | $1,455,338 | $351,820 | $357,102 | $ - | $2,164,260 | $162,320 | $162,320 | $324,639 | $2,488,899 | $2,488,899 |
| 13 | $1,455,338 | $351,820 | $357,102 | $ - | $2,164,260 | $162,320 | $162,320 | $324,639 | $2,488,899 | $2,488,899 |
| 14 | $1,455,338 | $351,820 | $357,102 | $ - | $2,164,260 | $162,320 | $162,320 | $324,639 | $2,488,899 | $2,488,899 |
| 15 | $1,455,338 | $351,820 | $357,102 | $ - | $2,164,260 | $162,320 | $162,320 | $324,639 | $2,488,899 | $2,488,899 |
| 16 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 17 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 18 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 19 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| TOTAL | $63,116,548 | $11,694,641 | $7,262,176 | $26,394,198 | $108,467,562 | $6,155,502 | $6,155,502 | $12,311,005 | $120,778,567 | $94,384,369 |

**TABLE L2**

ENERGY EFFICIENCY MEASURES CONSIDERED

## RESIDENTIAL

| High-use Lighting Measures LED | | | |
|---|---|---|---|
| | **From CFLs** | **From Incandescent** | **Total** |
| Remain Saturation | 60% | 75% | |
| Wattage | 22 | 100 | |
| Replace | 16 | 16 | |
| Diff | 6 | 84 | |
| Count | 35787 | 44744 | 80,521 |
| kW | 214.7 | 3757.6 | 3972.3 |
| Hrs Use | 1460 | 1460 | |
| kWh | 313,494 | 5,486,147 | 5,799,641 |
| MWh | 313 | 5,486 | 5,800 |
| Coin Factor | 15% | 15% | |
| Peak Savings | 0.90882 | 12.72348 | |
| Savings % | 27.3% | 84.0% | 69.5% |
| Unit Lifetime (yrs) | 17.1 vs 6.8 | 17.1 vs 0.7 | |
| Program Life (yrs) | 3 | 3 | |

| Solar Water Heating | Storage | Point of Use | |
|---|---|---|---|
| Saturation Target | 5% | 20% | |
| Count | 2,982 | 11,929 | |
| Base Usage (kWh) | 1,415 | 425 | |
| Replace Usage (booster) | 71 | 21 | 5% for booster |
| Diff | 1,344 | 403 | |
| Total kWh/yr | 4,009,456 | 4,811,347 | 8,820,804 |
| Total MWh | 4,009 | 4,811 | 8,821 |
| Coin Factor | 45% | 45% | |
| Peak Savings | 470.37 | 564.45 | 1,035 |
| Savings % | 95.0% | 95.0% | |
| Lifetime (yrs) | 10 | 10 | 10 |

| Refrigeration | | | | |
|---|---|---|---|---|
| Target Saturation | 100% | | 30% | achievable |
| Count | 17893.5 | 1,192.90 | per year | |
| Base Usage (kWh/kW) | 495 | | 0.065 | |
| Replace Usage | 420.92 | | 0.056 | |
| Diff | 74 | 15.0% | 0.010 | |
| Total kWh | 1,329,129 | | | |
| Total MWh | 1329.1 | | | |
| Coin Factor | 89% | | | |
| Peak Savings | 0.009 | | | |
| Savings % | 15.0% | | | |
| Lifetime (yrs) | 15 | use | 10 | yrs |

| Room Air Conditioning | | | |
|---|---|---|---|
| Saturation | 40% | | |
| Count | 23858 | 2385.8 | per year |
| Base Usage (kWh/kW) | 300 | wgt avg all types | 0.056 |
| Replace Usage | 225 | | 0.042 |
| Diff | 75 | 25.0% | 0.014 |
| Total kWh | 1,789,350 | | |
| Total MWh | 1789.4 | | |
| Coin Factor | 98.0% | | |
| Peak Savings | 0.014 | | |
| Savings % | 25.0% | | |
| Lifetime (yrs) | 10 | | |

| Residential Audits | | | | |
|---|---|---|---|---|
| Applied to total Res class load | | | | |
| Assumes 5% overall savings from audits, exclusive of other measures, over 5 year life | | | | |
| includes: | more efficient freezers | | | |
| | second refrigerator turn in | | | |
| | LCD TVs replacing CRTs | | | |
| | PC power management | | | |
| | building shell measures | | | |
| | Other (pool pump motors, cooking, appliances) upgrade efficiency | | | |
| these measures address a cross-section of load types, so are applied to the over Res Tariff load shape | | | | |
| | | | | |
| Base Usage/house | 1933 | | | |
| Savings % | 5% | | | |
| Savings kWh/house | 96.65 | | | |
| Lifetime (yrs) | 5 | | | |

## NON-LODGING COMMERCIAL

| Indoor Lighting Measures | | | | | | |
|---|---|---|---|---|---|---|
| | **Incandescent** | **Fluorescent** | **LED** | **Other** | **Total** | |
| Base energy | 2,380,801 | 34,105,450 | | 2,708,669 | 39,104,921 | |
| Savings percentage | 84% | 27% | 0% | | 28.6% | |
| Savings kWh for LED | 1,999,873 | 9,184,172 | | | 11,184,045 | |
| Lamps/Fixtures | 23,808 | 209,972 | | | | |
| | lamps | fixtures | Achievable % | | 75% | |
| customers | 7211 | 7211 | Net Savings kWh | | 8,388,034 | |
| per customer | 3.3 | 29.1 | Measure lifecycle | | 3 | years |
| Annual Net Savings kWh/yr | | | | | 2,796,011 | |

| Refrigeration | |
|---|---|
| Base energy kWh/yr | 5,265,830 |
| Savings percentage | 15% |
| Savings kWh/yr EE Measures | 789,874 |
| Achievable % | 50% |
| Net Savings kWh/yr | 394,937 |
| Measure lifecycle | 15 |
| Annual Net Savings kWh/yr | 26,329 |

| Air Conditioning | |
|---|---|
| Base energy | 23,742,082 |
| Savings percentage | 25% |
| Savings kWh EE Measures | 5,935,521 |
| Achievable % | 60% |
| Net Savings kWh | 3,561,312.32 |
| Measure lifecycle | 15 |
| Annual Net Savings kWh/yr | 237,421 |

| Commercial Audits | | | |
|---|---|---|---|
| Applied to total Comm class load for Non-lighting, Refrigeration and Cooling | | | |
| Assumes 5% overall savings from audit, exclusive of other measures, over 5 year life | | | |
| includes: | Cooking/Vending | | |
| | Office Equipment (PC and Copier/Printer Power Mgmt) | | |
| | Motors for Ventilation, etc. | | |
| | Exit signs | | |
| these measures address a cross-section of load types, so are applied to the overall Non-Lodging Comm Tariff load shapes | | | |
| | | | |
| Base Energy | | | |
| Ventilation | 926,003 | | |
| Office Equipment | 15,914,278 | | |
| Cooking/Vending | 1,211,648 | | |
| Misc/Exit | 15,612,433 | | |
| TOTALS | 33,664,362 | | |
| Savings percentage | 5% | | |
| Savings kWh EE Measures | 1,683,218 | | |
| Achievable % | 50% | | |
| Net Savings kWh | 841,609 | | |
| Measure lifecycle | 5 | | |
| Annual Net Savings kWh/yr | 168,322 | | |

## HOTELS

| Indoor Lighting Measures | | | | | | |
|---|---|---|---|---|---|---|
| | **Incandescent** | **Fluorescent** | **LED** | **Other** | **Total** | |
| Base energy | 2,913,910 | 6,352,618 | | 1,563,045 | 10,829,572 | |
| Savings percentage | 84% | 27% | 0% | | 38.4% | |
| Savings kWh for LED | 2,447,685 | 1,715,207 | | | 4,162,891 | |
| Lamps/Fixtures | 29,139 | 39,214 | | | | |
| | lamps | fixtures | Achievable % | | 75% | |
| customers | 57 | 57 | Net Savings kWh | | 3,122,169 | |
| per customer | 511.2 | 688.0 | Measure lifecycle | | 3 | years |

| Refrigeration | |
|---|---|
| Base energy | 6,308,155 |
| Savings percentage | 15% |
| Savings kWh EE Measures | 946,223 |
| Achievable % | 50% |
| Net Savings kWh | 473,112 |
| Measure lifecycle | 15 |
| Annual Net Savings kWh/yr | 31,540.77 |

| Air Conditioning | |
|---|---|
| Base energy | 21,581,141 |
| Savings percentage | 25% |
| Savings kWh EE Measures | 5,395,285 |
| Achievable % | 80% |
| Net Savings kWh | 4,316,228 |
| Measure lifecycle | 15 |
| Annual Net Savings kWh/yr | 287,749 |

| Hotel Audits | | | |
|---|---|---|---|
| Applied to total Comm class load | | | |
| Assumes 5% overall savings from audit, exclusive of other measures, over 5 year life | | | |
| includes: | Cooking/Vending | | |
| | Office Equipment (PC and Copier/Printer Power Mgmt) | | |
| | Motors for Ventilation, etc. | | |
| | Exit signs | | |
| these measures address a cross-section of load types, so are applied to the overall Hotel Tariff load shapes | | | |
| | | | |
| Base Energy | | | |
| Ventilation | 3,743,429 | | |
| Office Equipment | 1,206,124 | | |
| Cooking/Vending | 8,876,406 | | |
| Misc/Exit | 3,749,615 | | |
| TOTALS | 17,575,574 | | |
| Savings percentage | 5% | | |
| Savings kWh EE Measures | 878,779 | | |
| Achievable % | 50% | | |
| Net Savings kWh | 439,389 | | |
| Measure lifecycle | 5 | | |
| Annual Net Savings kWh/yr | 87,878 | | |

## APPENDIX M: NATURAL GAS ANALYSIS DETAILS

### CONTEXT

- Natural gas is being actively promoted across the region as an energy alternative, and could bring lower emissions, less pollution, and cost savings when compared to current diesel generation.
- But there are key risks, including long-term contracts with suppliers and the potential requirement to retrofit existing generators. Price volatility could well continue, as the long-term correlation between natural gas and diesel is currently unclear.
- Considering that LUCELEC would need to make a long-term bet to capture the benefits of natural gas, and that alternatives (including diesel, solar, wind, and perhaps geothermal) appear viable and increasingly cost-effective, the best path forward is to wait and monitor the natural gas option for Saint Lucia.

### OPPORTUNITY AND REQUIRED ELEMENTS

Natural gas could diversify Caribbean energy supply beyond oil.

- Natural gas has long been promised as a thermal generation option for Saint Lucia (and the Caribbean).
- Currently, most natural gas exports occur from oil producers (Russia, Norway, Qatar) via pipelines or high volume ocean-faring carriers.
- U.S. exports of natural gas started in early 2016 in earnest, and U.S. businesses and government actors are looking to export more, including at volumes appropriate for island nations.
- Right now, the Dominican Republic, Trinidad and Tobago, Puerto Rico, Jamaica, and very recently Barbados use natural gas for a small fraction of their power generation.
- Potential exporters for the Caribbean include the United States, Canada, Mexico, and Trinidad and Tobago, or re-export from the Dominican Republic, Puerto Rico, or Trinidad and Tobago.
- Natural gas as a fuel for electricity generation, when available, has typically outcompeted petroleum-based fuels, and recently even competes favorably with coal.
- Most of these cases are for continental grids with available pipelines.
- Emissions produced when burning natural gas are lower than alternative fossil fuels and about 25 per cent lower than diesel.
- However, fugitive methane, during the extraction or shipping process, can increase the global warming potential of natural gas, as methane is a potent greenhouse gas.

For natural gas to arrive in Saint Lucia at the appropriate volumes, the following must be established:

- Regional collaboration to attract suppliers of LNG (requiring at least five years preparation according to IDB)
- Long-term contracts for sourcing and importing natural gas and operating natural gas facilities (can be arranged by a supplier)
- Safe import facilities (requiring sub-zero temperatures and safety precautions) built in Saint Lucia, likely offshore

For natural gas to provide benefit to Saint Lucia, the following must be true:

- All-in gas costs must fall below EC$40.50 per MMBtu, or preferably below EC$32 per MMBtu to outcompete renewable options
- LUCELEC can sequence retrofits of generators 7, 8, 9, and 10—costing approximately EC$3,780 per kW (EC$116 million in total)
- To reduce fuel price volatility, natural gas would lack a correlation to global oil prices (which has been true recently, but not historically)

### COSTS, AVAILABILITY, AND BENEFITS

The cost of getting natural gas to an island like Saint Lucia can be considered with the following structure/flow:

1. Purchase the gas, under a specific volume contract.
2. Transport that gas to an export facility (likely in the U.S.).
3. Liquefy the gas (by compressing and cooling it to -161 degrees C) to bring down the volume to make shipping easier.
4. Ship the LNG to the island in a specialised container ship.
5. Regasify the LNG at an import facility that can be placed on-shore or offshore, and which would require specialised super-cold infrastructure. This facility could cost between EC$337 and $675 million (depending on arrangements).
6. Store the gas.
7. Transport the gas to the generation facility.
8. Burn the gas for electricity (which for Saint Lucia requires new generators or costly retrofits to existing generators).

Suppliers have offered the following cost estimates:

- Amortizing all the costs of the Saint Lucia facilities and operations (up until the gas enters LUCELEC's facility), the suppliers give (heavily caveated) estimates of EC$16.875 to $29.70 per MMBtu on top of the price of gas purchased in the U.S. (about EC$8 per MMBtu).
    - Approximately one-fourth of the total cost is considered to be on-island receiving facilities (regasification), not including the cost to retrofit existing generators.
- This approach presumes a 20-year contract.
- Separate estimates concurred on this range.
- Barbados shipments of LNG (although not for power generation) land at approximately EC$40.50 per MMBtu.

Natural Gas Availability

- Right now, all suppliers of natural gas to the Caribbean are focused on solving the volume and cost problems.
- They routinely admit that regional cooperation (multiple utilities and governments) will be required to justify shipping LNG to the region (as the smaller volumes for Saint Lucia or Grenada do not justify the shipping).
- Potential routes include Florida, Puerto Rico, the Dominican Republic, or Trinidad.

Estimates from suppliers show a cost-effective solution compared to continued diesel generation.

### RISKS

- LNG is not flammable or toxic (when in the liquid form), and accidental discharge does not pose significant environmental hazard.
- However, a leak can create a gaseous cloud that is highly flammable and dangerous.
  - LNG ships are often considered safer than diesel tankers, but storing LNG in highly pressurised containers (at sea or on land) requires constant oversight.
- In the U.S., FERC requires safety exclusion zones near LNG facilities, with the exact size being open to interpretation.
  - Offshore facilities could mitigate against this risk, but carry unique costs and risks.
- LUCELEC would likely be asked to sign a long-term agreement for receiving natural gas, committing the company and country to a commodity with high historical price risk (large swings).

### FORWARD-LOOKING CONSIDERATIONS

- Volatility—natural gas may not be a true hedge against oil prices.
- Upside is limited as the natural gas export market to the Caribbean is not an efficient market (price setters will ensure there is no significant delta from current diesel prices). Once the fuel contract has been signed, you are locked in.
- Coordination is required to provide a regional supply chain. Per IDB estimates, the first shipment of gas would arrive about 5 to 6 years after agreement is signed.

## APPENDIX N: OPERATING RESERVES APPROACH

Defining the operating reserves approach, both to approximate current operations and to future operations with and without variable renewables, is a critical factor in effectively modeling future scenarios. The section below outlines agreed-upon approaches for modeling operating reserves, as well as some alternatives.

### RESERVES DEFINITION:

The HOMER Energy Pro software models reserves as surplus operating capacity that can instantly respond to a sudden increase in the load or a sudden decrease in power output on the generation side. This type of reserve is often referred to as operating reserve, or spinning reserve. In the HOMER model, the reserve requirement can be met by generators that are operating below 100 per cent of their rated capacity and by batteries that have available stored energy. The HOMER model includes two ways of modeling or setting operating reserves, as a function of load and as a function of variable renewable output.

### DECISION ON OPERATING RESERVES AS A FUNCTION OF LOAD:

Partners in the NETS agreed upon setting the model to require operating reserves of 10 per cent of the load in the current hour. This approach is in line with how the system is operated today, while maintaining a conservative yet reasonable amount of operating reserves.

### DECISION ON OPERATING RESERVES AS A FUNCTION OF VARIABLE RENEWABLE OUTPUT:

A setting in the model requires a certain per cent of the output from variable renewables (solar and wind) as operating reserves. This requirement is in addition to the operating reserves as a function of load. In all scenarios there will be operating reserves of 10 per cent of the load, and in future scenarios that contain renewables, there will be additional operating reserves based on their variable output.

The HOMER default recommended values for the region are operating reserves of 25 per cent of solar output and 50 per cent of wind output. We've modeled a much more conservative approach with operating reserves of 100 per cent of solar output and 100 per cent of wind output. A third possible option exists, summarised in Table N1.

**TABLE N1**

SUMMARY OF OPERATING RESERVE SETTING OPTIONS

| Scenario Name | Operating Reserves as a Function of Solar Output (%) | Operating Reserves as a Function of Wind Output (%) |
|---|---|---|
| Option 1 (Current Setting) | 100 | 100 |
| Option 2 | 50 | 75 |
| Option 3 (HOMER Recommendation) | 25 | 50 |

When considering the operating reserve requirements to be used in the model, the number selected represents an overall average for the reserves that would actually be implemented. As they do today, the actual reserves may fluctuate from hour to hour based on many variables. In a future system with more renewable resources, reserves might also change over time. For example, in the first year after installing a large renewable resource, reserves might be set more conservatively while LUCELEC gains experience integrating this new resource into the system. In later years, these reserves might be relaxed after operation of the new resource is well understood. We need to select a standard number to use in the HOMER model for operating reserve requirements, acknowledging that the number we use is an overall average to represent how the system is operated (and will be operated in the future). The HOMER model will ensure that the selected amount of operating reserves are met in every hour of the simulation.

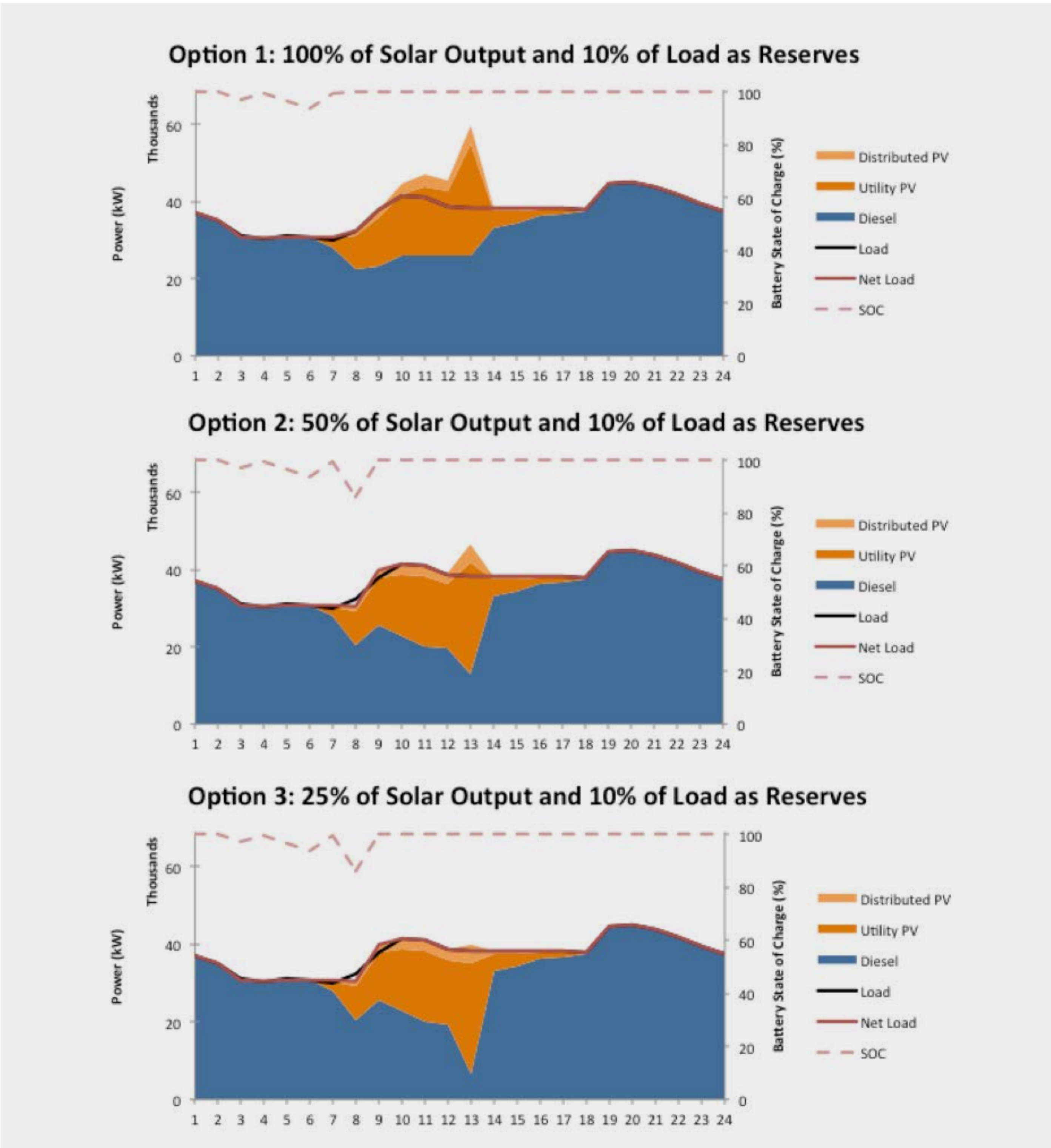
There are a few items to consider when selecting which operating reserve requirement to use in the HOMER model. One key item to note is that in the HOMER model, we are completing an hourly simulation. Operating reserve requirements are met in each hour based on the current load and the current output from solar and wind. Of course in the actual system, variations occur more frequently than every hour. The grid integration analysis that is underway with partners DNV GL will investigate some of these more dynamic aspects of system operation. However, in order to complete that analysis, we need to select a starting point for operating reserve requirements to use in the HOMER model.

Another key consideration is that in a future system with many renewable resources, these are likely to be spread across diverse geographic locations that experience different weather. Therefore, a sudden change in cloud cover in one location does not necessarily affect the output from all solar resources, for example. As we have seen from other locations that have started to incorporate large amounts of renewable resources, weather forecasting can help with day-ahead planning of generation resources. The operating reserves are in place to handle any unexpected changes in renewable output.

As an example, the results from the HOMER model were examined on the day with the largest hourly change in solar output. The model for the year 2019 was used, with an installed capacity of 30 MW of solar and 15 MWh of battery storage as a test case. On September 6, the largest drop in solar output between two hours occurs in the early afternoon, with production dropping from 28.8 MW in one hour to 4.7 MW in the next. The modeled hourly operation of the system on this day is shown in Figure N1, which compares the three suggested options for operating reserve requirements. The load and operating reserve requirements are met in all three cases; setting a lower operating reserve requirement allows less diesel generation to be utilised, saving fuel and O&M costs.

**FIGURE N1**

OPTIONS FOR OPERATING RESERVE REQUIREMENTS ON SEPTEMBER 6, 2019



# APPENDIX O: SOLAR RESOURCE ASSESSMENT

## METHODOLOGY

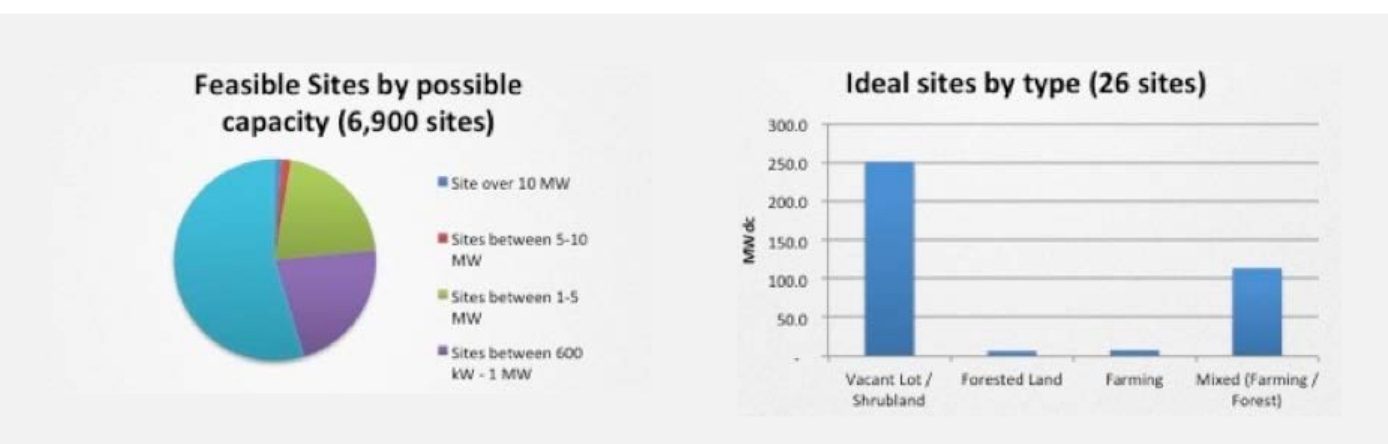
- Assessment based on aerial imagery data, building footprint data, parcel maps, and LIDAR survey.
- Analysis performed in geographic information system (GIS) software, constrained by constructability parameters for ground-mount, rooftop, and carport PV (e.g., no ground-mount PV development within 100 metres from coastline, limited slopes, and access to distribution grid and roads, etc.).
- Results show potential solar project development (sites) as well as total capacity broken down by the various constructability parameters (for example, 277 MW of the 380 MW ground-mount potential is less than 50 metres from an interconnection point).
- Summarise methodology, constructability parameters, and resulting energy estimates into report and spreadsheet results, delivered to LUCELEC and the Saint Lucia Government by June 10th.

## GROUND-MOUNTED ASSESSMENT

**Core Criteria:** Viable sites must have: sufficient area, little shading, setbacks from nearby obstructions, and no overlap with environmental or geographic features (waterbody, flood zone, etc.).

- The team initially found 6,900 sites across the island meeting the criteria, providing the land area for 8 GW of solar potential.
- The team then sought out ideal sites—larger areas with extremely low slope (flat terrain) that are close to a point of interconnection (less than 500 metres).
- This sub-categorisation led to a determination of 26 sites, **providing the land area for 380 MWdc of solar potentia**l.
- These 26 sites are mostly located on vacant lots or shrubland.

**FIGURE O1**
GROUND-MOUNTED ASSESSMENT



## PARKING CANOPY ASSESSMENT

**Core Criteria:** Viable sites must have: sufficient parking area (approximately 1,200 square metres, enough to site 200 kWdc) and setbacks from nearby obstructions to avoid shading.

- The team initially found 104 sites across the island meeting the criteria, allowing for 46 MWdc on parking structures.
- The team then sought out ideal sites—larger areas closer to an access road and closer to a point of interconnection (less 50 metres).
- This sub-categorisation led to a determination of 42 sites, providing the land area for 21 MWdc of solar potential.

**TABLE O1**

PARKING CANOPY RESULTS: BREAKDOWN BY DISTANCE TO ACCESS ROAD

| Entire Island 200 kW dc | Number of Sites | Capacity (MWp) |
|---|---|---|
| Between 0–5 m | 26 | 13 |
| Between 5–10 m | 8 | 5 |
| Between 10–20 m | 6 | 1 |
| Between 20–50 m | 2 | 1 |
| Total | 42 | 21 |

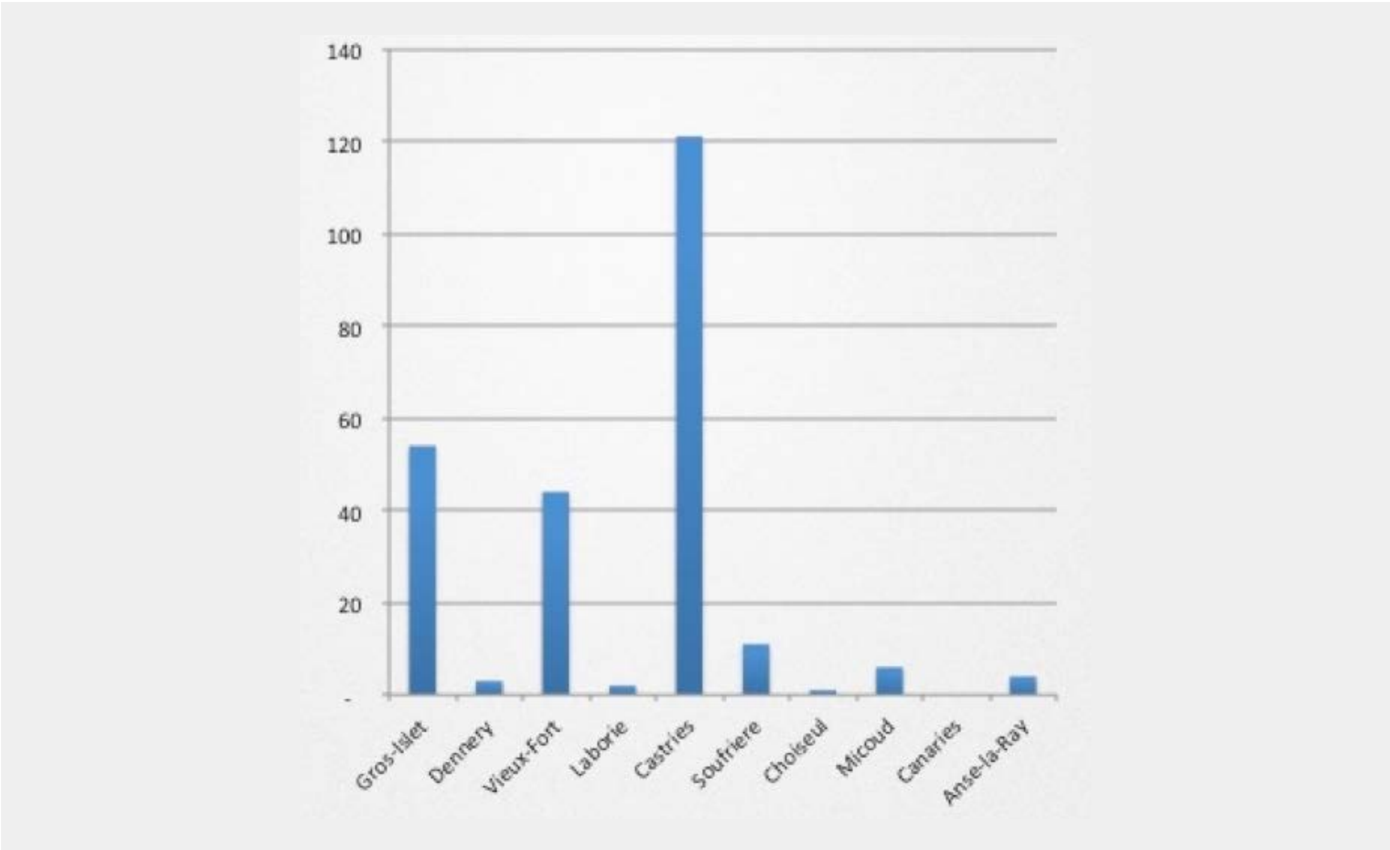
## COMMERCIAL ROOFTOP ASSESSMENT

**Core Criteria:** Viable sites must have: sufficient area, appropriate pitch of roof (no north-facing roofs), structural integrity (as estimated from satellite imagery), and setbacks to avoid shading.

- The team initially found 246 sites across the island meeting the criteria, providing the land area for 22 MWdc of solar potential.
- The team then sought out ideal sites—larger areas with low roof slopes that are close to a point of interconnection (less than 500 metres).
- This sub-categorisation led to a determination of 26 sites, **providing the land area for 6 MWdc of solar potential**.
- Most viable sites are in Castries, Gros Islet, and Vieux Fort.

Residential sites were not captured in this assessment (due to data quality limitations). There will be residential opportunities, largely driven by roof structure.

**FIGURE O2**
POTENTIAL COMMERCIAL SOLAR SITES BY DISTRICT



## APPENDIX P: SOLAR VARIABILITY AND SYSTEM OPERATIONS

After comparing modeled solar PV production to actual LUCELEC data, and historical solar information from the Hewanorra International Airport, the following conclusions emerged:

1. **a.** Significant solar variation (both day-to-day, and hour-to-hour) was already built into HOMER due to varying cloud cover. This result generally matches with observed data from LUCELEC's 75 kW solar PV system at Cul De Sac Power Station and with long-term solar data collected at the international airport.

**FIGURE P1**

CHART OF MODELED DAILY SOLAR PRODUCTION

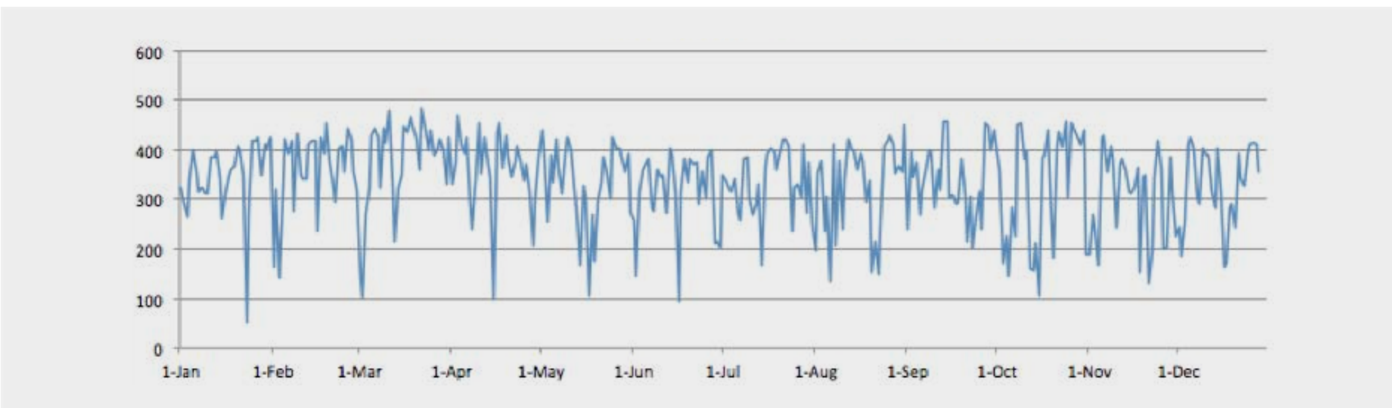
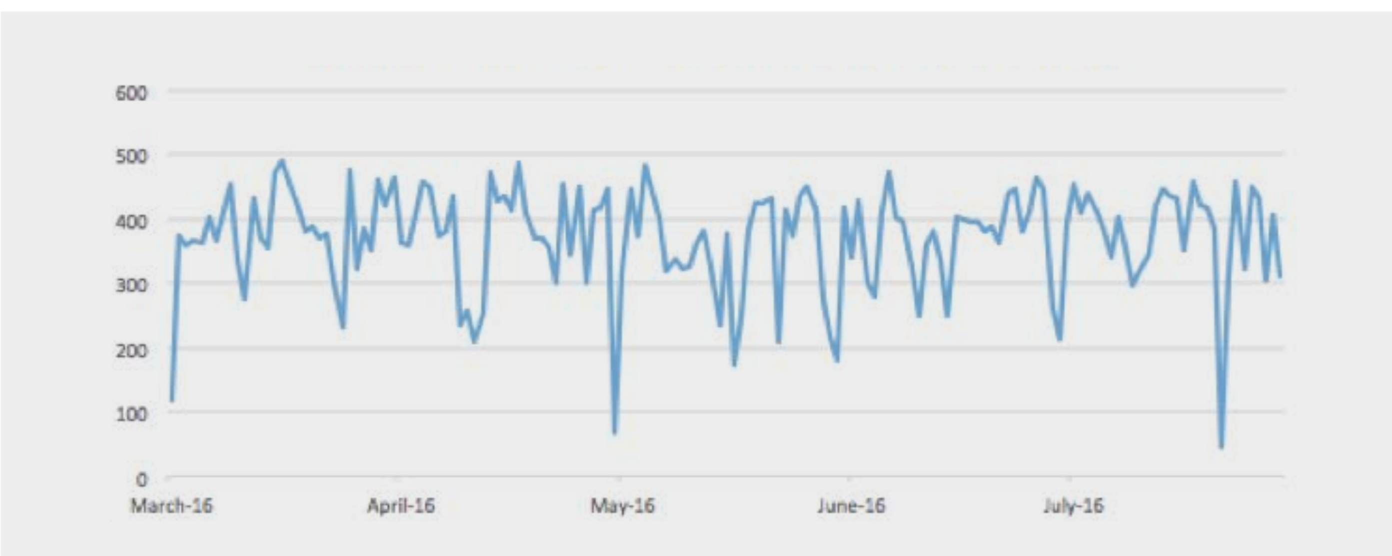



**FIGURE P2**

CHART OF LUCELEC 75 KW SOLAR PRODUCTION



At first glance, clear variation occurs in both the real data and the modeled data, with numerous days experiencing production of half of the average production or less. The HOMER input data projects 6 per cent of the days in an average year having production of 50 per cent or less. For the observed LUCELEC data (from the last six months), 3 per cent of the 151 days had 50 per cent or less production (versus daily average). When we assess the HOMER data over the same timeframe as the LUCELEC data (March to August), we project 5 per cent of the 151 days having 50 per cent or less production.

**FIGURE P3**

FREQUENCY OF DAILY SOLAR PRODUCTION VS. AVERAGE

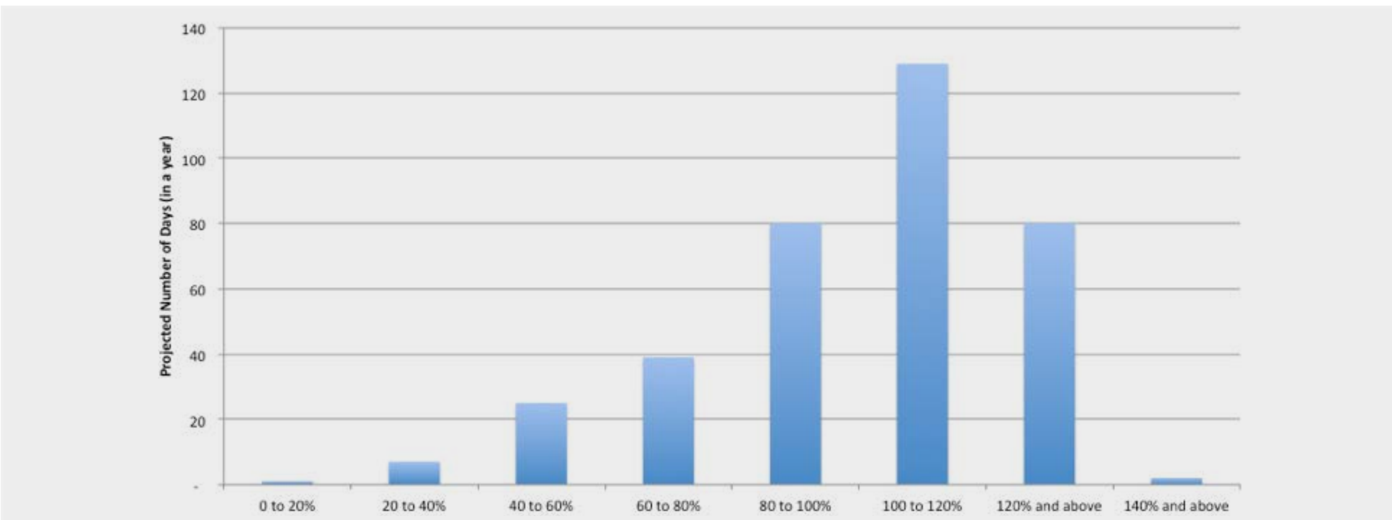
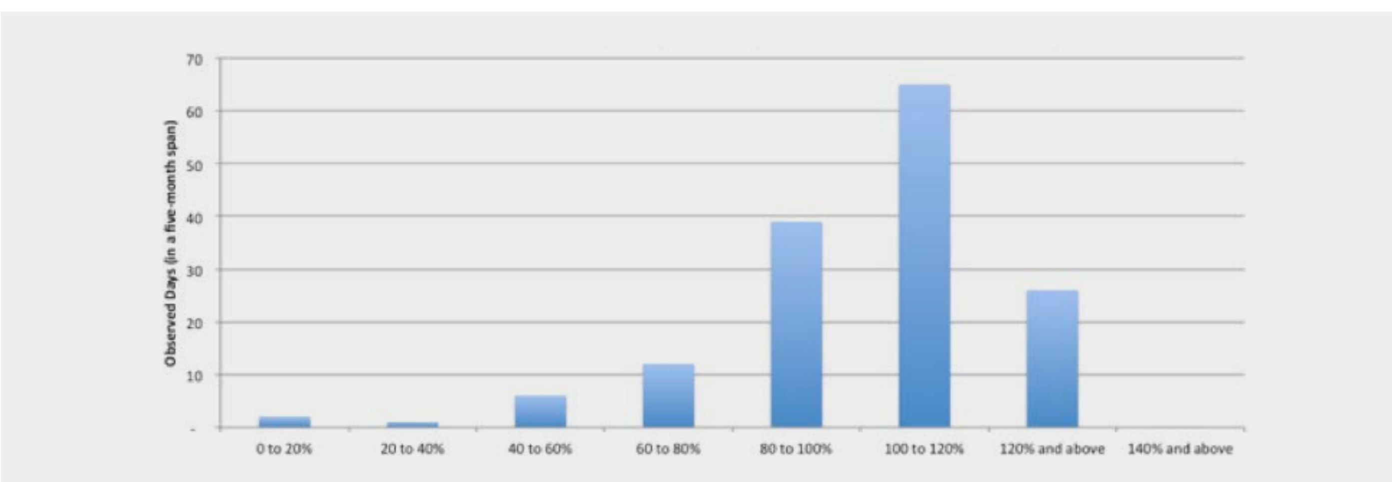



**FIGURE P4**

AVERAGE PRODUCTION FOR 75 KW PER HOMER PROJECTIONS = 345 KWH PER DAY




*Average Production recorded for the LUCELEC 75 kW system = 369 kWh per day*

1. **b.** The team has also looked at the “worst” solar day, as in the lowest production with the heaviest cloud cover. For the observed LUCELEC data, the 75 kW system’s minimum production occurred on August 11, 2016, with production of 43.83 kWh or 12 per cent of average. The HOMER data projects the minimum solar day in a year providing 15 per cent of average energy production.

As more data is collected by the LUCELEC 75 kW system, we would expect to see a closer match to long-term forecasts (i.e., the HOMER input data).

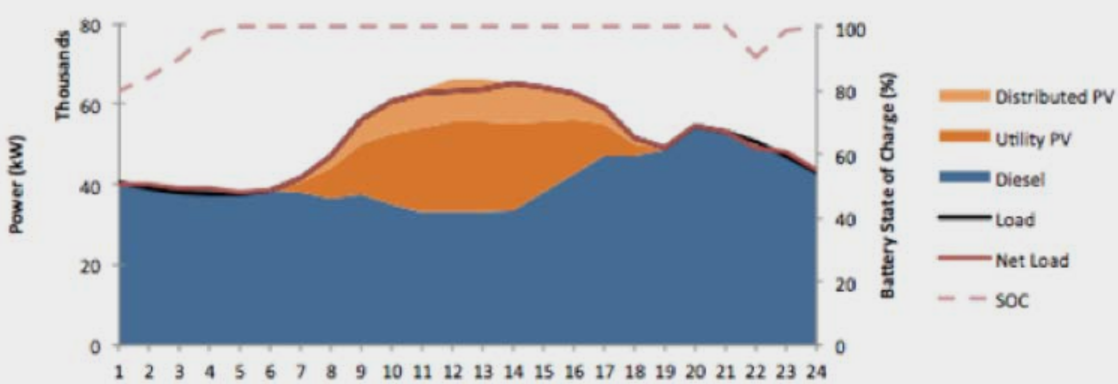
Certainly these results depend somewhat on system size, inverter type, location on the island, system degradation over time, and other factors, but our general finding is that the weather and temperature modeling assumptions match observed solar data.

1. **c.** When combined with other resources, the modeled system will be able to meet both load and required operating reserves in 2024, as well as meeting the n-2 requirement.

The model results for the Solar + High DG (decentralised) case in the year 2024 are shown for specific days in the dispatch charts on the following pages. In this scenario, the system includes 32.4 MW of utility-owned PV and 15.9 MW of distributed PV, along with 15 MWh of battery energy storage. The system also includes 67.8 MW of total diesel generator capacity, representing generators 4–10 that are part of the system today (generators 1–3 are presumed to be retired).

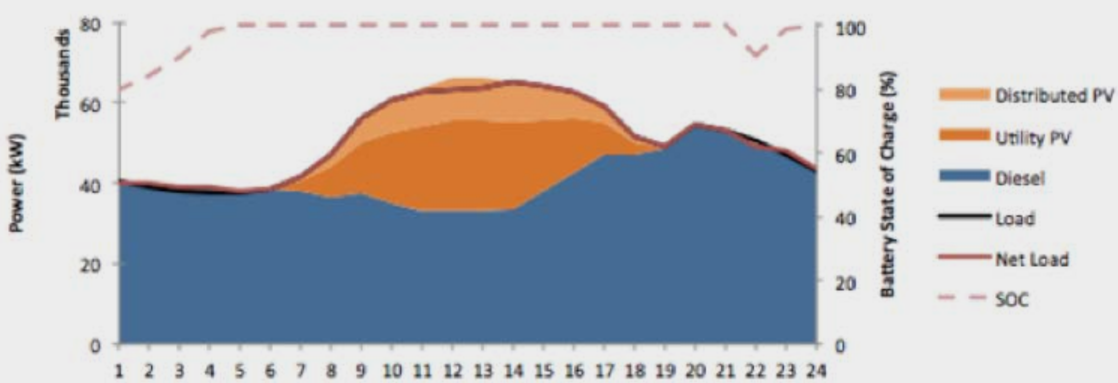
First, the dispatch of resources on the day with the peak load (June 23) is plotted. This chart has already been shared during the August review of the NETS results, and is included here for reference.

**FIGURE P5**
2024 SOLAR/HIGH DG



The following chart shows the day with minimum solar output (January 23). Diesel generators and the battery energy storage system are utilised to meet the load and operating reserve requirements on this day, with very little output from solar. While the load on this day is lower than the peak load experienced during the year, the chart shows an example of using diesel generation capacity that remains in the system in the future to meet the load on a day without much solar production; this approach would also successfully meet load and operating reserve requirements on the day with the peak load if that happened to align with a day with low solar production.

**FIGURE P6**
2024 SOLAR/HIGH DG, MINIMUM SOLAR

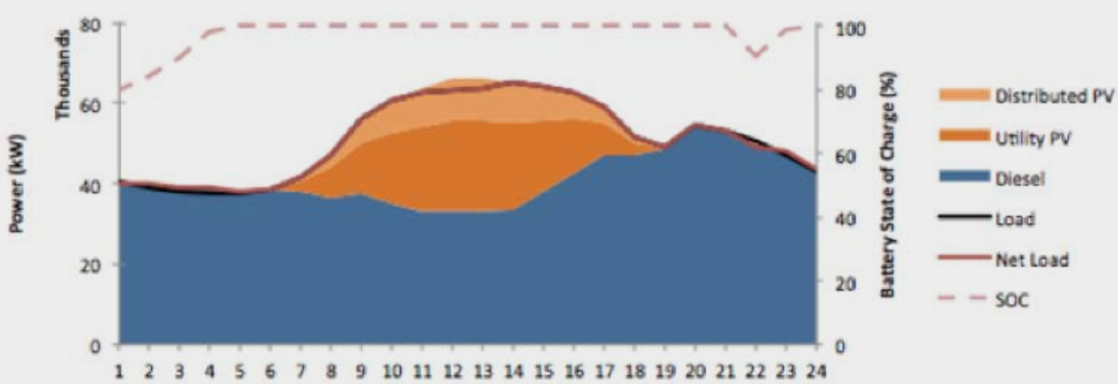


Along with identifying the day with minimum solar output, we identified three days in a row with relatively low solar output (October 13–15); these days are plotted in the chart below. For these three days, the total solar output corresponds to 46 per cent of the average (mean) three-day period.

Again, the diesel generators are relied upon on these days. Even through a three-day low-solar period, the batteries remain at 80 per cent state of charge or higher, to support reserve requirements.[xvii]

**FIGURE P7**

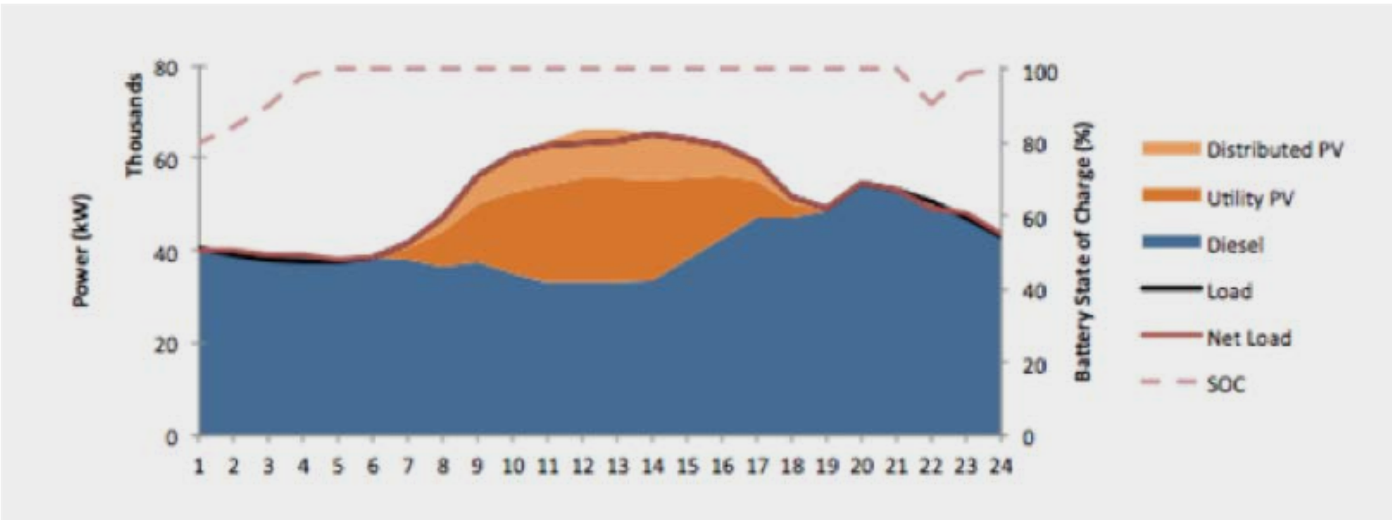
2024 SOLAR/HIGH DG, 3 LOW SOLAR DAYS




xvii The batteries, sized by the model to maximise economic benefit, provide a battery bank of 15 MWh, which is able to discharge up to 45 MW of total power for short periods of time.

**FIGURE P8**

2024 SOLAR/HIGH DG, MAXIMUM NET LOAD




Finally, we identified and plotted the day that contains the hour with the maximum net load (defined as the load minus the solar output). This hour occurs in the afternoon on October 20 in the model, when loads remain high but cloud cover sharply reduces the afternoon production of the solar projected in the system. As seen in the chart below, diesel output ramps up, and storage discharges to meet both the load and operating reserve requirements even with a large decrease in solar output in the afternoon.

The charts above show several modeled days, including those with peak load and minimum solar output. One situation that is not explicitly shown is the case where the peak load, minimum solar output, and maintenance on one or more diesel generators all occur at the same time. Our modeling uses annual data for both load and solar irradiance, so seasonal and daily alignment is considered; modeling results demonstrate an ability to meet both load and operating reserve requirements on each modeled day across a variety of load amounts and solar availability

### 1. Approach

Hourly solar irradiance data was provided by DNV GL (using Meteonorm data, which is typically used in the PVsyst software), as part of preliminary modeling completed for the 3 MW project that is now underway. This data was used in the HOMER model for the NETS, and results in a modeled capacity factor of 20 per cent (so far the LUCELEC 75 kW has a 20.5 per cent capacity factor).

When compared against the LUCELEC 75 kW data and historical Saint Lucia data from Hewanorra International Airport, these are generally commensurate, both at the average and at the minimum and maximum range.

HOMER projections for total output from a 75 kW system are slightly lower than LUCELEC-observed data (primarily due to assumptions of annual cloud cover)—6.5 per cent lower production than LUCELEC-observed data (345.1 kWh production in an average [mean] day assumed by HOMER versus 369.2 kWh average [mean] observed at Cul De Sac). Due to only six months of collected data from the 75 kW system, the observed average from the LUCELEC system will change over time, perhaps reducing this discrepancy.

**FIGURE P9**

HOMER PROJECTIONS VS. LUCELEC MEDIAN DAY SOLAR OUTPUT

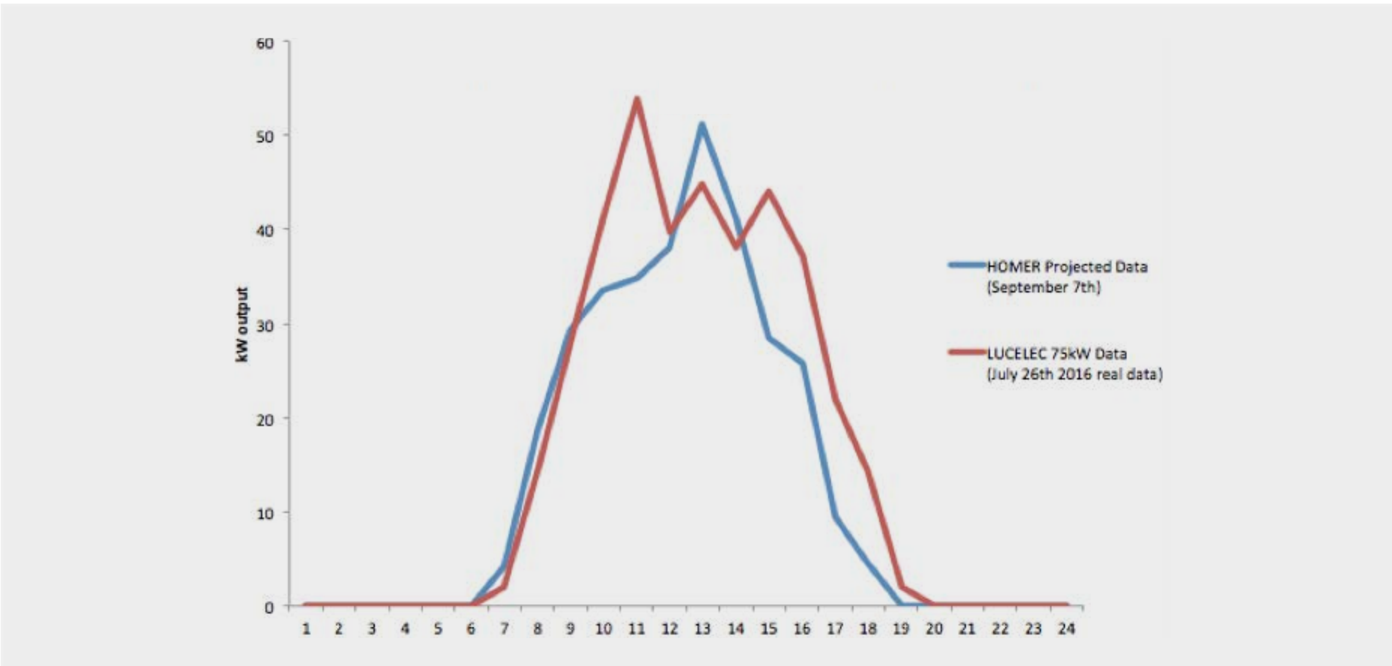
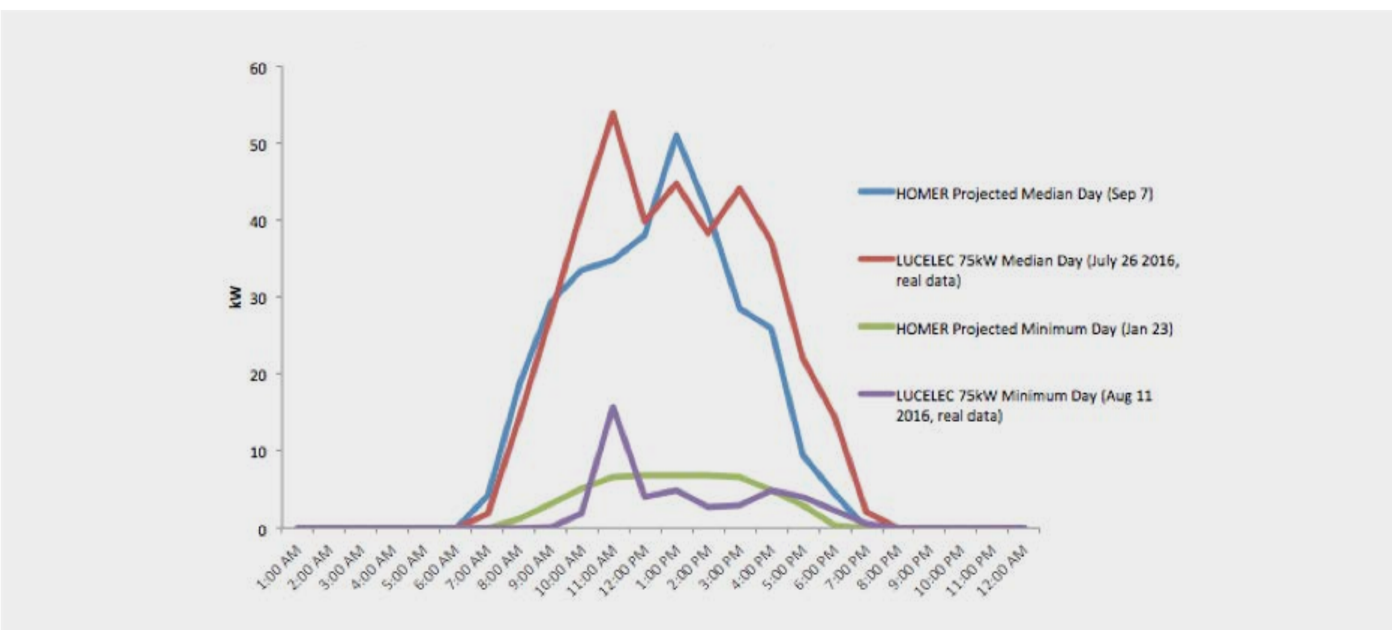



**FIGURE P10**

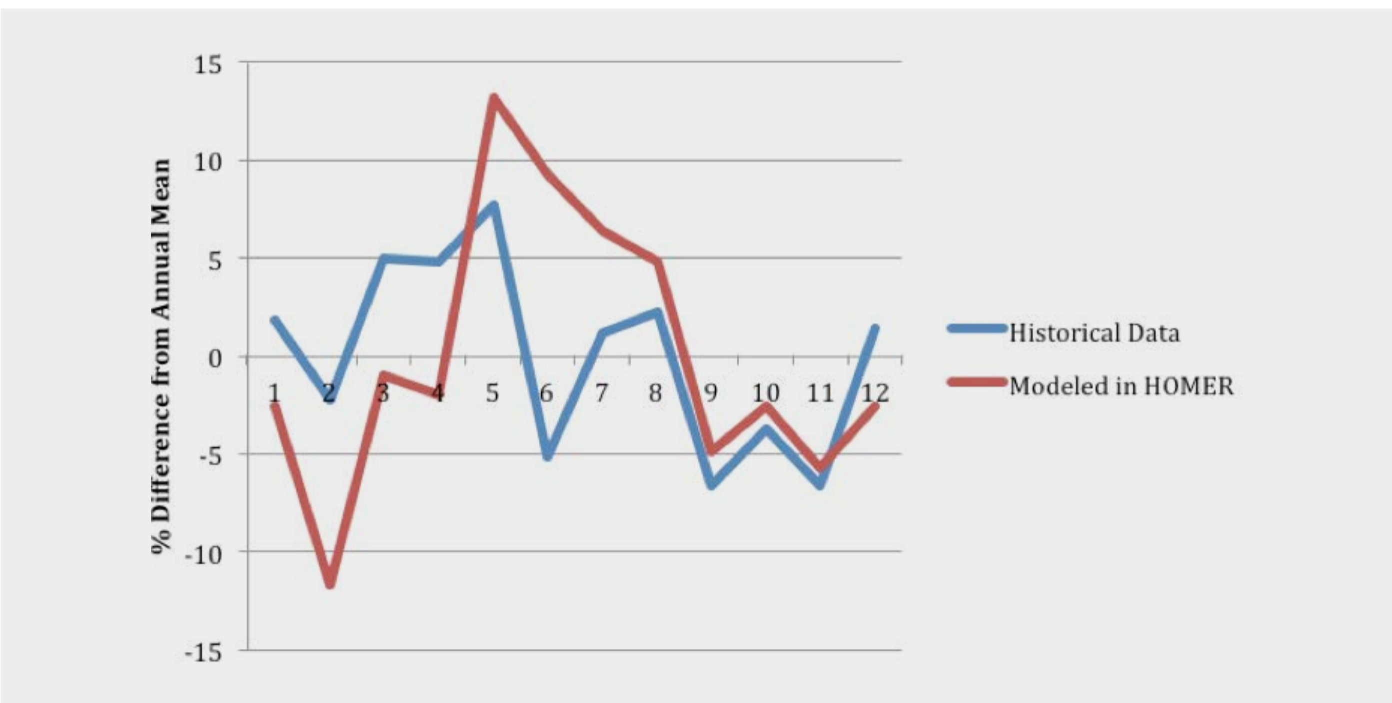
COMPARISON OF MINIMUM AND MEDIAN DAY



When compared against historical measurements of hours of sunshine taken at Hewanorra International Airport, the input data to our model is again generally commensurate. While the monthly hours of sunshine in historical data differs on average 4 per cent from the annual average, the monthly hours of sunshine in the modeled data differs on average 5.6 per cent from the annual average. This indicates that the modeled data includes slightly more variation in solar availability than the historical data measured at the airport. Another possible reason for the difference is that the historical data was measured more granularly than the hourly data used in the modeling. The chart below shows the monthly difference from the annual mean as a per centage for both sets of data. As the chart shows, the two sets of data match closely in their variation from annual average for the second half of the year. For the first half of the year, the modeled data includes more variation than the actual observed historical data, resulting in a conservative modeling approach used in the HOMER models.

**FIGURE P11**

MONTHLY DIFFERENCE FROM THE ANNUAL MEAN



**2. Additional Considerations:**
Multiple days of extremely low solar will exhaust the batteries during the day, reducing available reserve capacity. However, low nighttime loads will allow other resources (diesel, geothermal, or, to a lesser extent, wind) to recharge the batteries, providing required reserves at minimal solar output conditions.

Isolated clouds over differing size of solar systems as well as number of inverters and inverter characteristics will change the degree to which cloud cover reduces output. However, no matter the choice of system, heavy clouds can reduce solar output by 80 to 90 per cent of the average hour. This result is reflected in both the LUCELEC 75 kW data and in the HOMER input data. Locations of the solar projects, in particular whether they are all inland, on the coast, or in other microclimates that may exist on the island, modify the typical cloud cover, and eventually provide some benefit from locational diversity for solar (both from utility-owned and distributed).

Maximum power point trackers (MPPTs), electronic tracking devices typically included in the inverter, are used to optimise the power generated by solar panels in sites where the irradiance conditions are less than optimal (these are different from mechanical tilt and orientation trackers). This is an important design consideration for solar arrays moving forward. It is hardly likely that the weather conditions experienced by the panels will be equal to standard test conditions.

An MPPT constantly adjusts to find the optimal balance between current and voltage to give the maximum power with the external conditions. In other words, MPPTs minimise the impact of cloudy conditions, by constantly recalibrating to ensure maximum power yield. Typically, panels facing in one direction and tilted to the same angle can be connected to one MPPT. This is an important design consideration with increasing distributed generation. Ensuring that the sizing of the solar array (i.e., number of panels per MPPT) is optimised lessens the impact on energy generation in cloudy conditions.

## CONCLUSION
Solar variability is clearly a concern, but utility-owned and operated batteries can reduce much of this risk. The IRP modeling includes continued use of existing diesel generation; while the generators are used less during days with lots of solar availability, they are still available to be used during days with less solar.

## APPENDIX Q: SCENARIO CRITERIA

### TABLE Q1

SCENARIO CRITERIA

| Goal | Points (out of 100) | Formula | Notes |
|---|---|---|---|
| **Reliability** | **45 total** | | |
| N-2 condition ensured | Max of 20 | Scenarios where all hours meet n-2 condition receive 20 points, with others being adjusted by the per centage difference versus best (for example, a scenario with 10% of annual hours of n-2 not being met will receive 18 points). | Quantitative: Measured in 2035. Examine across all hours of the modeled year (2035). Highest per centage receives 20 points and then mathematically subtract from other scenarios. |
| Projected system faults or violations | Max of 20 | The score equals 15 minus the number of technical faults projected in the transmission and distribution studies (by 2025) | Quantitative: Measured in 2035. Fewer faults implies a more reliable system. All scenarios have been tested to be as reliable as the reference case. This would mean all scenarios should score at or very near the maximum here (per the DNV GL grid integration results). |
| Controllability of generation assets | Max of 10 | Partner Ranking—partners determine a score from 0 to 10 for each scenario | Qualitative measure to determine LUCELEC's resources to operate the system effectively – (though this can be informed by the per centage of assets that are dispatchable, and the amount of solar, storage, and wind under direct LUCELEC control). Measured in 2035. |
| **Cost Containment** | **40 total** | | |
| Average annual rate (over the 20 years) | Max of 15 | Lowest rate scenario receives 15 points, with others being adjusted by the per centage difference versus best (for example, a scenario that is 10% higher in average rate would get a score of 13.5, rounded to nearest 10th). | Quantitative: This is the projected customer rate, given current regulations. As all rate projections were relatively close together (as scenarios were economically optimised), the scores should be generally similar. Measured from 2016 to 2035. |
| Total cost to operate the system | Max of 10 | Sum the 20-year total cost to operate the system. Lowest rate scenario receives 10 points, with others being adjusted by the per centage difference versus best. | Quantitative: This metric measures the total cost to operate the system (lower is better), but doesn't have defined rate of return for investments (that is covered under the annual rate category above). |
| Reduced volatility (exposure to global fuel price changes) | Max of 15 | Partner Ranking—partners determine a score from 0 to 15 for each scenario | Qualitative: Based on partner input. This can be informed by the degree to which each scenario responds to different fuel prices. Each scenario will be tested with two fuel scenarios: 1) high and volatile, and 2) low and relatively stable fuel prices. |
| **Energy Independence** | **15 total** | | |
| Achieving renewable energy targets | Max of 5 | The 35% renewable energy target for 2020 was not an explicit target of the analysis. However, many scenarios reach this target in years after 2020. The earliest scenario to reach this target receives 5 points. Reaching it a year later would earn 4 points, and two years later, 3 points, etc. | Quantitative: Based on the year by which renewable energy targets are met. Reaching the target by 2020 is possible, but was not found to be economically optimal given current assumptions. Reaching the target in subsequent years is both possible and economically beneficial. |
| Carbon emissions | Max of 5 | The carbon emissions baseline can be derived from the diesel –fuel-only reference case. Each scenario is then compared against that reference case, in year 2035, with scores being = 5- (1- scenario per centage reduction) * 5 | Quantitative: % reduction vs. baseline. Higher per cent reductions will help meet Saint Lucia's National Determined Contribution (carbon reduction goals submitted to the UNFCCC). There is some overlap with the other energy security categories. |
| Domestic energy (security) | Max of 5 | Partner Ranking—partners determine a score from 0 to 5 for each scenario | Qualitative: Based on partner input on which new energy mixes will most improve domestic energy security. This metric can be informed by the degree to which different scenarios reduce required fuel imports for electricity generation (data can be provided here to help make the rankings). |

## APPENDIX R: RENEWABLE PENETRATION—FOUR WAYS TO DEFINE

For the following example island grid, renewable penetration can be calculated in four different ways. The first two (based on energy or capacity) are the most common. Different definitions of renewable penetration yield very different targets and results for the same grid.

**1. Penetration based on Energy**

3 MW (average renewable energy (RE) output)
60 MW (average load)
**= 5%**
A 10 MW (installed capacity) wind farm with 30 per cent capacity factor will on average produce 3 MW, compared to an average load of 60 MW.

**2. Penetration based on Capacity**

10 MW (RE capacity)
150 MW (total installed capacity)
**= 6.67%**
The simplest calculation; installed RE capacity compared to total installed capacity.

**3. Penetration based on Peak Load**

10 MW (peak RE output)
100 MW (peak load)
**= 10%**
The maximum amount of energy a wind farm can produce compared to the overall peak load.

**4. Penetration based on Instantaneous Peak**

10 MW (peak RE output)
40 MW (load during peak RE output)
**= 25%**
The time when the wind farm has its maximum output is likely at night, during a time of minimum load.

**TABLE R1**
SCENARIO CRITERIA

| Electrical Grid Characteristics (Illustrative) | | | | | |
|---|---|---|---|---|---|
| Peak Load | Minimum Load | Total Capacity | RE Capacity | RE Capacity Factor | Load Factor |
| 100 MW | 40 MW | 150 MW | 10 MW | 30% | 60% |

EN

# ENDNOTES

# ENDNOTES

1. LUCELEC 2015 Annual Report

2. Invest Saint Lucia, 2015

3. RMI Analysis based on system outages, country GDP, and associated cost of losses.

4. LUCELEC 2015 Annual Report

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