Final Report

2015 Integrated Resource Plan

Commonwealth Utilities Corporation

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leidos

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EXECUTIVE SUMMARY

This report was prepared by Leidos Engineering, LLC (Leidos) for the Commonwealth Utilities Corporation (CUC) and describes the 2015 CUC Integrated Resource Plan (IRP) and the process used to develop it.

The IRP was designed to seek firm bids for future resource options for the islands of Rota, Saipan, and Tinian of the Commonwealth of Northern Mariana Islands (CNMI) and model CUC's generation system throughout the planning horizon, given various scenarios and a range of assumptions regarding future loads and fuel price projections, while meeting the energy demands of CUC's customers. The results of the IRP provide planning options for building an optimized resource mix while working toward reducing electric rate impacts for CUC's customers.

CUC sought the development of this IRP with the expectation that the utility would be making changes to its resource portfolio and that their stakeholders need to understand the impact of these changes. The 25-year planning horizon of the IRP is wrought with uncertainty for CUC, including but not limited to each of the following issues:

- CUC's aging infrastructure
- Future CUC load growth, particularly given impacts of potential tourism growth and associated hotel construction and distributed rooftop photovoltaic (PV) generation
- Renewable generation potential, including utility scale PV, wind, and geothermal generation
- Fuel oil price volatility
- CUC's financial condition and its impact on CUC's ability to procure new generating assets

This report describes the activities conducted by Leidos in the development of the IRP and the results and findings of the IRP.

IRP Process

Developing the IRP entailed the following five broadly defined groups of tasks.

- Stakeholder engagement activities and the development of a comprehensive IRP Strategy
- Developing and issuing a Request for Proposals for Energy Supply
- Developing comprehensive assumptions characterizing the CUC system
- Qualifying and screening potential resource options
- Conducting detailed scenario modeling of potential resource options

Stakeholder Engagement Activities

Leidos conducted numerous stakeholder interviews and workshops, with both internal CUC and external stakeholders. The objectives of the interviews and workshops were to (1) introduce the goals and timeline of the IRP, (2) discuss challenges and strengths CUC would have to overcome/maintain to succeed with the IRP, and (3) obtain input regarding community perception and communication strategies. The stakeholder engagement process also included the development of an IRP Communication Plan for CUC.

Key elements of the strategy for developing the IRP were discussed at the stakeholder meetings and workshops. These elements included the overall strategy of developing IRP scenarios which incorporated stakeholder input, issuing an energy supply request for proposals, understanding the existing CUC system, developing engineering estimates to supplement the IRP assumptions as appropriate, and evaluating a series of potential residential and commercial demand-side management (DSM) programs for inclusion in the IRP. The primary takeaway from the stakeholder engagement activities was the strong stakeholder desire to lower CUC's generating costs, thus lowering customer rates.

In addition to working with CUC staff and management, Leidos also engaged with additional IRP working group participants, including staff from the National Renewable Energy Laboratory (NREL) and staff from CUC's economic and rate advisor, Economist.com.

Request for Energy Supply Proposals Development

A key component of the IRP was the development and public issuance of a Request for Proposals for Energy Supply (RFP). The RFP itself was developed in collaboration with CUC and received extensive review by CUC procurement, legal, and operations staff. Additionally, the RFP was certified by the CNMI Attorney General. The RFP was publicly released on November 20, 2014.

Assumptions Development

During the stakeholder engagement and Energy Supply RFP development phase, Leidos concurrently developed comprehensive assumptions related to CUC's generating systems, demand and energy requirements, projected fuel prices, and other information required to complete the IRP. A detailed description of the assumptions development process is included in Section 3 of this report.

RFP Proposals Qualification and Resource Options Screening

The RFP proposals were evaluated for their completeness and responsiveness to the Technical Proposal requirements provided in the RFP, the technical and performance characteristics of the projects and/or integrated solutions being proposed, and for the financial health and operational experience of the proponent.

Qualified projects proposed through the Energy Supply RFP process, as well as a potential Liquefied Natural Gas (LNG) solution involving LNG infrastructure and associated generating units, were further evaluated using a Levelized Cost of Energy (LCOE) screening process.

The LCOE screening analysis evaluated capital, operating (fixed and variable), fuel, and other costs (if any) for each of the resource options (including renewable options), and then estimated the all-in dollars per megawatt-hour ($/MWh) cost of each resource for a range of plausible capacity factors.

In parallel with the LCOE analysis, a series of residential and commercial DSM programs were parameterized and evaluated, primarily using the Total Resource Cost (TRC) test benefit-cost ratio. As a result of the strong performance of such measures under the TRC framework, said measures were assumed as being endorsed and modeled via a commensurate load forecast reduction (with associated measure costs included) as part of the downstream IRP scenario modeling.

IRP Scenario Modeling

The final analysis phase of the IRP consisted of conducting detailed production cost modeling. A number of IRP scenarios were developed, designed to comprehensively evaluate a range of potential resource options available to CUC. The production cost modeling of each scenario incorporated virtually all of the assumptions developed for the IRP, projecting the hourly dispatch of each generation resource on a least cost basis as necessary to meet hourly load projections.

The IRP scenarios included five Base Cases, which were then modified in additional portfolio and sensitivity cases. The five Base Cases included:

- **Case 1: Business as Usual (BAU) Case.** The BAU case serves as the reference case and is used to compare production cost differentials of all other cases. This case assumed that CUC could extend the life of the existing asset base through the end of the IRP study period.
- **Case 2: Light Fuel Oil (LFO) Replacement**. This case assumes that the least cost LFO candidate resource, as determined through the LCOE screening process, is sited at the existing CUC Power Plant 4 site.
- **Case 3: Heavy Fuel Oil (HFO) Replacement**. This case assumes that CUC will retire the existing Power Plant 1 units and rely upon the HFO bid received for future generation.
- **Case 4: LNG Replacement – Saipan Only**. This case assumes that CUC will retire the existing Power Plant 1 units and rely upon a potential LNG alternative for Saipan only.
- **Case 5: LNG Replacement – All Islands**. Assumptions for Case 5 are the same as those in Case 4 for Saipan. In addition, this case assumes that the existing units on Tinian and Rota will retire and be replaced by new natural gas-fired reciprocating units.

Upon completion of the five Base Cases, additional cases were developed to evaluate the individual solar PV candidate resource options received during the RFP process in combination with the BAU case described previously. Further, each of the five Base

Cases were then combined with PV resource options to determine whether any cost savings may be available by adding solar PV resources to baseload options.

IRP Results

The Base Cases are intended to quantify the production cost of generation using three fuels - LFO, HFO, and LNG – compared to the BAU case. Table ES-1 below provides the levelized production cost comparison of all five Base Cases. The LFO and HFO cases are similar in cost to the BAU case. Both Case 2 and Case 1 burn LFO, but the additional cost of the new units in Case 2 pushes the levelized cost above the BAU case. Sections 3 and 5 of this report contain details of each Case described below, including installed capacity, assumed retirements, system reserve margin, and more.

Table ES-1
Base Case Levelized Production Cost Comparison ($/MWh)

Case	Levelized Cost ($/MWh)	Diff. From Case 1 ($/MWh)	% Difference from Reference Case (Case 1)
Case 1 – BAU	464.48		
Case 2 – LFO	480.40	15.93	3.4%
Case 3 – HFO	460.42	(4.05)	-0.9%
Case 4 - LNG Saipan	353.42	(111.05)	-23.9%
Case 5 - LNG All	334.23	(130.24)	-28.0%

The LNG cases are substantially lower cost than the fuel oil cases as shown in Table ES-1, but are based on planning level estimates (not actual bids) for LNG infrastructure, shipping costs, and new generation unit capital costs. A detailed feasibility study is needed to improve the accuracy of the estimated costs associated with the LNG cases.

IRP Findings

This report summarizes the results of our investigations and analyses up to the date of this report. Changed conditions occurring or becoming known after such date could affect the material presented herein to the extent of such changes. Nothing contained in this report is intended to indicate conditions with respect to safety or to security regarding the proposed resource additions or to conformance with agreements, codes, permits, rules, or regulations of any party having jurisdiction with respect to the construction, operation, and maintenance of the CUC power plants, which matters are outside the scope and purposes of this report.

The assumptions, evaluations, and analyses conducted for purposes of the CUC IRP support several key findings when reviewing the production cost results in Section 5:

- Energy efficiency measures such as residential lighting and water measures and commercial lighting and refrigeration measures are projected to be materially less costly than any of the supply side options, including oil and LNG fueled generation alternatives, as well as PV generation alternatives.
- PV generating facilities are projected to be materially less costly than any of the oil and LNG fueled alternatives. However, their relative savings is significantly lower than the LNG alternative as a result of the bounded capacity value of PV during the utility's peak demand periods and the relatively low AC capacity factor that can be expected from a new PV installation.
- The LNG fueled alternative is projected to be materially less costly than any of the oil fueledgeneration alternatives.
- All of the oil fueled generation alternatives, including the BAU, LFO, and HFO options, are not projected to have materially different costs relative to each other.

Next Steps

The IRP process has provided CUC with enough information to identify generation solutions worthy of further investigation. Before making the final selection, additional studies may be needed to clarify the costs and other impacts associated with some of the potential generation options.

The diesel-based proposals were generally turnkey solutions at an existing power plant location and have been fully modeled during this initial IRP process. However the LNG, HFO and PV scenarios need to be modeled in greater detail in order to fully evaluate those options. Detailed feasibility studies will develop a more comprehensive understanding of the costs of LNG delivery and distribution systems and any potential energy security concerns with fuel delivery for that option, regulatory and environmental challenges associated with HFO power plants, and issues with identifying land for a potential utility-scale PV power plant. CUC may also consider additional energy efficiency and conservation programs given the favorable modeling of DSM solutions.

Other factors need to be considered before determining the best generation solution for CNMI. As an example, the IRP process did not incorporate disaster resiliency and the possible future effects of climate change into the selection process for new generating assets. Climate change is associated with increasing frequency and strength of storms and rising sea levels, which could potentially threaten CNMI's power systems as a result of high winds and storm surge in low-lying coastal areas. However, following the devastation caused to Saipan's power generation and distribution system by

Typhoon Soudelor, CUC has decided to incorporate storm resiliency into the final selection process.

In addition to the above actions, Leidos has identified the following recommended actions related to CUC's operations and future planning efforts:

1. ***IRP Implementation Plan.*** Develop an IRP implementation plan including specific milestones.
2. ***Collect Operations Data.*** Collect detailed operations data related to hourly loads, generation, distributed PV penetration, sales, fuel costs, and other key system parameters. This will aid future planning efforts and operational budgeting and benchmarking.
3. ***Fuel Price Hedging Program***. Develop a fuel price hedging program to compensate for the inherent volatility in fuel prices. Such a program could be used to mitigate the price swings that are inevitable in the world oil markets, and which ultimately impact CUC's customers.
4. ***Cost of Service Study***. Conduct a cost of service study to identify the true costs of service by customer class and to quantify administrative and general expenses associated with CUC's operations. The results of such a study would be very useful in determining whether rate design modifications may be appropriate to recover CUC's true costs of service.

Section 1
INTRODUCTION

In January 2014, Commonwealth Utilities Corporation (CUC) released a request for proposals for consulting services to assist CUC in preparing a 25-year Integrated Resource Plan (IRP) and Energy Supply Analysis.

The IRP was designed to seek firm bids for future resource options for the Commonwealth of Northern Mariana Islands (CNMI) and model CUC's generation system throughout the planning horizon, given various scenarios and a range of assumptions regarding future loads and fuel price projections, while meeting the energy demands of CUC's customers. The results of the IRP provide planning options for building an optimized resource mix while working toward reducing electric rate impacts for CUC's customers.

CUC Background Information

The CNMI, a chain of 14 islands in the Pacific Ocean located approximately 1,600 miles east of the Philippines is a Commonwealth of the United States (U.S.) that is geographically isolated from the mainland U.S. CUC is a semi-autonomous public corporation in the CNMI with the authority to produce and distribute power and sell drinking water, and collect, treat, and sell or dispose of wastewater.

CUC is responsible for the construction, maintenance, operation, and regulation of all CNMI Utility Services, and provides electric power, water and sewer services to the islands of Saipan, Tinian, and Rota. CUC is completely dependent on fossil-fueled electric generation facilities, with the exception of a relatively small number of customer owned distributed photovoltaic (PV) generating systems totaling approximately 2 megawatts (MW) alternating current (AC) (MW_{AC}) of installed capacity. Electricity is generated by four diesel-fueled power plants: two on Saipan and one each on Tinian and Rota. Generating capability is approximately 70 MW on Saipan, 20 MW on Tinian, and 7 MW on Rota.

With all of its electric power plants powered by fuel oil, and given the lack of oil or natural gas reserves in the islands, CUC's electric customers pay a fuel surcharge that varies with the Mean of Platts Singapore (MOPS) oil price index, which results in electricity prices in recent years that have been three to four times the U.S. average. Most large hotels have generators and generate electricity for their own use when fuel surcharges are high. The CUC is seeking both conventional and renewable alternative electricity sources to reduce the cost and increase the reliability of its existing diesel-fueled generation.

The CNMI government adopted a renewable portfolio standard (RPS) in 2007 that required CUC to obtain 10 percent of its electricity from renewable energy sources in 2008, rising to 80 percent in 2014. However, compliance is required only if there is a cost-effective way to meet the standard, and currently CUC does not own any renewable generating resources.

IRP Background Information

CUC undertook this IRP with the expectation that the utility would be making changes to its resource portfolio and that their stakeholders need to understand the impact of these changes. The 25-year planning horizon of the IRP is wrought with uncertainty for CUC, including but not limited to each of the following issues:

- CUC's aging infrastructure
- Future CUC load growth, particularly given impacts of potential tourism growth and associated hotel construction and distributed rooftop PV generation
- Renewable generation potential, including utility-scale PV, wind, and geothermal generation
- Fuel oil price volatility
- CUC's financial condition and its impact on CUC's ability to procure new generating assets

The IRP is fundamentally focused on answering two core questions, namely:

i. What is the domain of plausible resource scenarios (IRP scenarios) that are actually available to CUC over a long-term planning horizon?

ii. What are the analytical steps that must be taken to objectively evaluate these IRP Scenarios to arrive at a holistic plan to meet CUC's long-term resource needs (IRP results)?

The IRP strategy focused on the interdependencies and areas of analysis required to develop defensible IRP scenarios and analyze such scenarios to provide defensible IRP results. The figure below defines the overarching CUC IRP Strategy for development of the IRP scenarios, the guiding principles of which are explained further below.

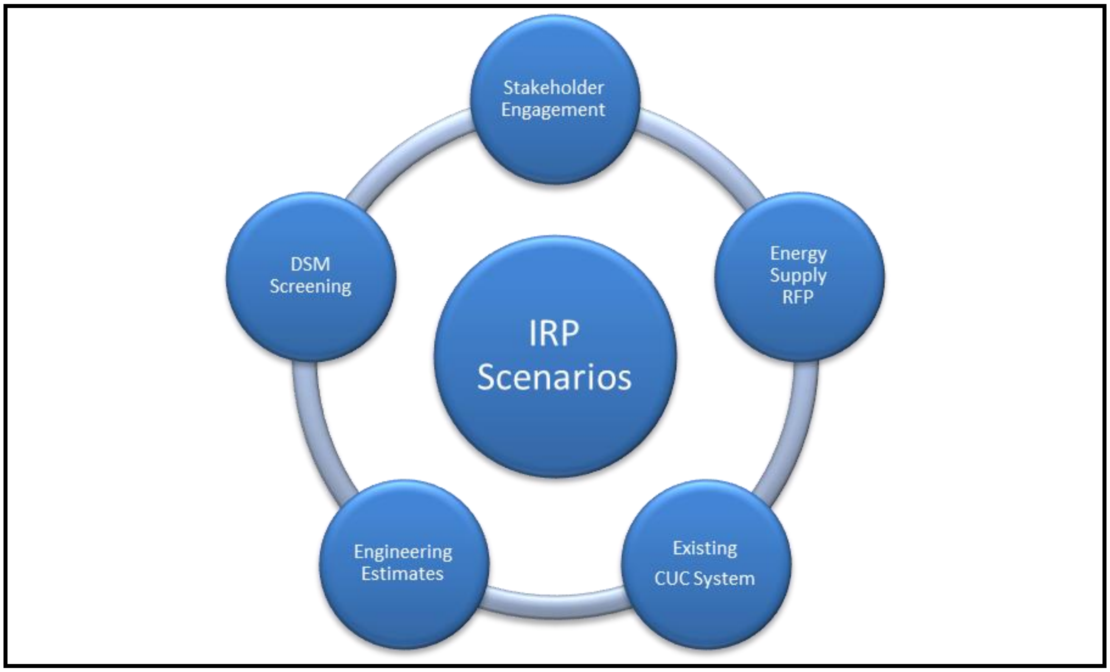


Figure 1.1: IRP Strategy

IRP Scenarios – Guiding Principles

Each of the five rings around the core IRP Scenarios ring in the figure above represents an interdependent area of analysis that was executed in order to develop the IRP Scenarios that are actually available to CUC (which drove their ultimate definition). The following guiding principles defined the strategy in each area:

- ***Stakeholder engagement*** at strategic periods in the IRP ensured consensus regarding the overarching IRP approach and the objectives of the planning activities.
- ***A detailed Energy Supply RFP process*** was essential to the availability of real-world input assumptions for power supply resources that were based on actual vendor bids; this was especially critical for the island communities of Saipan, Tinian, and Rota given their remote location and the challenges that poses with respect to development of "generic" resource assumptions for new construction and/or conservation and demand-side management (DSM) programs.
- ***CUC's Existing System*** was fully examined to characterize existing CUC power assets in terms of cost and performance, anticipated retirement schedules, and ongoing or impending major maintenance as well as to estimate, within reason, the cost to CUC (and their customers) of continuing to operate utility assets as has been done to date (or "business as usual" conditions). Further, a detailed analysis of existing and future load growth/contraction and capacity requirements was critical to projecting a realistic amount of potential capacity expansion and/or DSM programs to serve such requirements. Finally, the cost of delivered fuel to serve not only CUC's current assets but also potential new assets was projected

based on CUC's own insights regarding how fuel is currently delivered to the island.

- ***Engineering Estimates*** were required to supplement assumptions gathered during the RFP process for commercially viable technologies that were not found in the responses to the RFP.
- ***A DSM screening*** was required for the same reason as the Engineering Estimates above, but with respect to the DSM landscape.

Overview of the IRP Development Process

Developing the IRP entailed the following five broadly defined groups of tasks, which were either informed by the IRP Strategy described above, or, in the case of the stakeholder engagement process, helped shape the IRP Strategy. These activities, which are more fully described below, were as follows:

- Stakeholder engagement activities
- Developing and issuing a Request for Proposals for Energy Supply (RFP)
- Developing comprehensive assumptions characterizing the CUC system
- Qualifying and screening potential resource options
- Conducting detailed scenario modeling of potential resource options

Stakeholder Engagement Activities

Leidos Engineering, LLC (Leidos) initiated the external stakeholder engagement process by conducting in-depth interviews with stakeholders representing various customer segments and regulators. The objectives of the interviews were to (1) introduce the goals and timeline of the IRP, (2) discuss challenges and strengths CUC would have to overcome/maintain to succeed with the IRP, and (3) obtain input regarding community perception and communication strategies. The list of external stakeholders interviewed included the CUC Board of Directors and representatives from the U.S. Environmental Protection Agency (EPA), the CNMI Public School System, the Commonwealth Public Utilities Commission, the Chamber of Commerce, and the Hotel Association of the NMI. Leidos also conducted similar interviews with nine internal CUC staff representing the full range of utility operations and management.

In addition to the stakeholder interviews, Leidos also conducted internal and external stakeholder workshops for wider audiences. The purpose of the stakeholder workshops was to provide an overview of CUC operations, introduce the IRP project and how it will be conducted, and obtain their input. Meeting attendees at the external stakeholder workshop included representatives from the CNMI Department of Community & Cultural Affairs, the CNMI Public School System, the Division of Fish and Wildlife, the CNMI Department of Public Works, the Commonwealth Public Utilities Commission, the Chamber of Commerce, the CNMI Bureau of Environmental and Coastal Quality, the CNMI Legislature, and several major hotels, resorts, and retailers. Leidos also conducted a similar workshop with 21 CUC employees.

Ultimately, the primary theme revealed repeatedly during the stakeholder engagement activities was the strong desire to lower CUC's generating costs, thus lowering customer rates. This message was emphasized over other items related to environmental and sustainability concerns, fuel diversity, and other issues raised during the stakeholder interviews and workshops.

The IRP process also included the development of a Communication Plan for CUC. The input obtained from the internal and external stakeholders was used to develop the core message and the communication strategies defined within the Communication Plan. Designed to guide CUC's communication efforts in support of the IRP process, the Communication Plan included the goals for the IRP process, as well as protocols describing future updates regarding the progress and ultimately the results of the IRP.

Request for Proposals Development

A key component of the IRP was the development and public issuance of an RFP. To maximize responses to the RFP from qualified proponents and to minimize the time required for the evaluation/acquisition of resources, Leidos developed an initial Request for Information (RFI) and established a developer "reach out" program. These efforts alerted prospective proponents to the upcoming RFP, solicited feedback that informed the development of the RFP, and provided an initial orientation to CUC's IRP process and short-term expectations.

Two webinar sessions were hosted to explain the IRP process to developer participants and describe the contents and scheduling for the RFP. In total, approximately 30 different developer organizations attended the sessions. A press release regarding the RFP to major trade publications and media contacts was released, as well as a direct e-mail to developers on the distribution list letting them know the date when the RFP will be issued.

The RFP itself was developed in collaboration with CUC and received extensive review by CUC procurement, legal, and operations staff. Additionally, the RFP was certified by the CNMI Attorney General. The RFP was publicly released on November 20, 2014.

Assumptions Development

During the stakeholder engagement and Energy Supply RFP development phase, Leidos concurrently developed comprehensive assumptions related to CUC's generating and distribution systems, demand and energy requirements, projected fuel prices, and other information required to complete the IRP. A detailed description of the assumptions development process is included in Section 3 of this IRP, and is supplemented by detailed appendices associated with the report.

RFP Proposals Qualification and Resource Options Screening

After extending the deadline for responding to the RFP to ensure maximum developer response to the RFP, a Source Selection Committee (SSC) composed of six members of CUC staff and three members of Leidos staff was convened. The RFP proposals were evaluated for their responsiveness and completeness of Technical Proposal requirements provided in the RFP, the technical and performance characteristics of the projects and/or integrated solutions being proposed, and for the financial health and operational experience of the proponent.

SSC members reviewed each proposal thoroughly and completed a Qualifying Scoring Worksheet for each proponent. The Scoring Worksheets included a number of evaluation points and metrics in six categories. The categories and a sample of the types of questions included in each category follows:

- **Basic Proposal Requirements**
  - Did the proposal provide all required forms, provide a good understanding of the proposed project and its benefits, and reflect a careful and well thought out effort?
- **Equipment and Engineer, Procure, and Construct (EPC)**
  - Did the proposal provide adequate descriptions of commercially available, island-tested technologies? Did the proposal describe key equipment vendors and engineering firms? Did the proposal have major equipment secured with defined delivery time periods?
- **Environmental Attributes, Permits, and Related Issues**
  - Did the proposal identify permits, licenses, and environmental assessments that would be required for the proposed project? Did the proposal identify the agencies involved in issuing the required permits and licenses, and did the proposal identify a plan with a timeline for obtaining the required permits and licenses?
- **Site Control**
  - Did the proposal provide a proposed project site map and layout plan? Had the proposed project secured a site, or a development plan for securing a site?
- **Project Management and Experience**
  - Did the proposal provide a clear project organization chart, and background information and resumes for key individuals on the project team? Did the proposal provide detailed descriptions of other projects completed by the project team? Did the proposal identify the entities responsible for supporting the project, such as lenders, advisors, engineers, and counsel?
- **Project Financing and Credit Worthiness**
  - Did the proposal completely describe the proposed project from a financial and legal perspective? Did the proposal provide descriptions of any equity partners in the project? Did the proposal provide a financing plan for the

project? Did the proposal provide audited financial statements? Was the proposer a creditworthy counterparty?

After independently scoring each proposal, the SSC met to collectively review the proposals. If the majority of the SSC members, five or more, determined that a particular proponent was qualified, then the SSC as a group agreed that the proponent was qualified and would be considered during the next phase of the IRP, the Levelized Cost of Energy (LCOE) screening. SSC members reviewed their scoring carefully and signed attestation statements confirming the scores. The original, signed Attestation Statements were submitted and are on file with the CUC Procurement Office.

Qualified projects proposed through the Energy Supply RFP process, as well as a potential Liquefied Natural Gas (LNG) solution involving LNG infrastructure and associated generating units, were further evaluated using an LCOE screening process.

The LCOE screening analysis provided quality control on input assumptions for each potential resource option, as well as a basis for eliminating redundant RFP proposals with similar technologies. The screening evaluated capital, operating expenses (fixed and variable), fuel, and other costs (if any) for each of the resource options (including renewable options), and then estimated the all-in dollars per megawatt-hour ($/MWh) cost of each resource for a range of plausible capacity factors. A complete description of the LCOE screening analysis is included in Section 4 of this IRP.

In parallel with the LCOE analysis, a series of residential and commercial DSM programs were parameterized and evaluated, primarily using the Total Resource Cost (TRC) test benefit-cost ratio. As a result of the strong performance of such measures under the TRC framework, said measures were assumed as being endorsed and modeled via a commensurate load forecast reduction (with associated measure costs included) as part of the downstream IRP scenario modeling. Refer to later sections of this report for a definition of the proposed DSM portfolio.

IRP Scenario Modeling

The final analysis phase of the IRP consisted of conducting detailed production cost modeling. A number of IRP scenarios were developed, designed to comprehensively evaluate a range of potential resource options available to CUC, as determined in the RFP proposals qualification and resource screening phase described above. A detailed description of the IRP scenarios, their associated production cost modeling, and the results of that modeling are included in Sections 4 and 5 of this report.

The results of the IRP scenario modeling informed the IRP's vision for CUC's future, providing a long-term road map for CUC's management and planners as they make decisions going forward.

Section 2
CUC PLANNING RISKS AND UNCERTAINTIES

Throughout the course of conducting this IRP, Leidos met and spoke with CUC extensively to identify the various risks and uncertainties that the utility will face over the coming 25 years of the IRP planning period. Such risks and uncertainties were used to inform the development of the scenarios and resource options that were modeled to produce the results presented in this IRP report.

Identification of Risks and Uncertainties Faced by CUC

A key component to developing the planning scenarios for this IRP was the identification and qualitative evaluation of the risks CUC would face over the study's 25-year planning horizon. Key risks identified as part of multiple conversations between Leidos and CUC staff included the following, which will be discussed in greater detail in the subsections that follow:

- CUC's aging infrastructure
- Future CUC load growth, particularly given impacts of potential tourism growth and associated hotel construction and distributed rooftop PV generation
- Renewable generation potential, including utility scale PV, wind, and geothermal generation
- Fuel oil price volatility
- CUC's financial condition and its impact on CUC's ability to procure new generating assets

CUC's Current Generating Assets

CUC currently generates all of its electricity primarily with two fuel oil fueledreciprocating engine power plants on Saipan, one on Tinian, and one on Rota. The assets on Tinian are currently owned and operated by a third party, with the output sold to CUC under a long-term Power Purchase Agreement (PPA). CUC has the ability to extend the Tinian PPA every five years; after discussions with CUC, the IRP assumes that the Tinian PPA will be extended through the end of the IRP study period at the same terms and pricing conditions as the existing PPA. The Rota power plant, owned and operated by CUC, is significantly oversized relative to Rota's current and projected demand. Further, the plant is composed of units, which are 17- and 5-years old. As such, under both the base case load forecast and under the high load forecast which assumes significant tourism and hotel growth, the Tinian and Rota generating systems are projected to not have any capacity needs in this IRP.

The Saipan facilities are in a markedly different situation. The primary plant, which supplies the vast majority of Saipan's power, needs is Power Plant 1. With its eight units between 25 and 35-years old, Power Plant 1 is reaching the end of its useful life expectancy. CUC's plant engineers spend considerable time and effort on a daily basis maintaining Power Plant 1, often needing to fabricate new replacement parts as needed, because specific replacements are often simply unavailable due to the vintage of the plant. As Power Plant 1 continues to age, it is a significant risk to CUC's ability to provide reliable power to Saipan. CUC's primary backup generation on Saipan is Power Plant 4, which also is reaching the end of its useful life expectancy, with five of its seven units at least 35-years old. Identifying cost-effective options for CUC to replace these power plants as soon as practicably possible is a key objective of this IRP.

Future CUC Load Growth

Future CUC load levels are projected to largely be dependent upon three related factors: "organic" retail sales growth across each of the three interdependent islands, potential hotel and casino developments related to tourism growth, and potential rooftop PV installations that may reduce future load to be supplied by the grid. There is inherent uncertainty in all of these primary load growth drivers, and cumulatively they result in a significant amount of risk to CUC's long-term planning efforts, as CUC seeks to secure new, reliable generation sources.

Retail sales including residential, commercial, and governmental customer classes are typically forecasted using econometric variables, which relate electric sales to economic indicators such as real Gross Domestic Product (GDP) of the CNMI, population, revenue by customer class, and other econometric adjustment factors. Absent a CNMI population projection from the Moody's Corporation, there are no externally derived projections of independent variables that would typically be used to develop GDP growth for the CNMI, which has faced significant challenges to its economy following the collapse of the textile industry from 2006-2008, with employment across all sectors decreasing 13 percent from 2008-2009 alone. Further, there is a reasonable possibility that discrete load additions may materialize on the CUC system as a consequence of new hotel or casino loads. Given the uncertainty regarding the potential for these new loads to materialize, forecasting future loads for CUC's system is particularly challenging. Finally, the recent explosive growth of the rooftop PV industry in the U.S. has the potential to extend to the CNMI, given the high cost of electricity in the islands. To the extent that there may be a significant uptake of rooftop PV in the CNMI, the associated volatility and uncertainty in net loads to be served by CUC contributes to the overall uncertainty of CUC's future load growth.

Renewable Generation Potential

The 2013 CNMI Strategic Energy Plan, developed by the National Renewable Energy Laboratory (NREL) and funded by the Office of Insular Affairs (OIA) screened several renewable energy technologies and found there was likely a number of renewable energy technologies such as solar, wind, biomass, waste-to-energy, and geothermal energy potentially available to CUC. However, the study also found that further resource assessment and grid interconnection analyses would need to be undertaken to determine the specific potential for large-scale renewable power generation facilities.

CUC understands the potential for renewable energy resources in the CNMI, and also is aware that the beneficial economics of several renewable technologies may present opportunities to lower CUC's production costs while at the same time, avoid fossil fuel consumption. CUC has had several renewable energy developers visit the CNMI and make introductory offers and development pitches to the CNMI government and CUC management. However, these unsolicited offers have been randomly presented with no adherence to any energy planning process. Further, the technologies and indicative pricing have been wildly disparate, leaving CUC management with an unclear picture of what the true costs of renewable energy may be in the CNMI.

Fuel Oil Pricing and Volatility

As described above, CUC currently generates all of its electricity using diesel-fueled reciprocating engines. As such, CUC is acutely sensitive to both the general pricing trends of diesel fuel in the world oil markets, as well as the inherent volatility incorporated into oil prices. Additionally, the CNMI's geographic isolation imposes significant shipping costs onto CUC's fuel prices, further increasing the impact of oil pricing to CUC's customers.

CUC is highly interested in reducing its reliance upon oil fueledgeneration. A primary option for doing so may be to incorporate utility-scale renewable energy generation into CUC's portfolio. However, even relatively high amounts of renewable capacity will likely still require some amount of fossil-fueled, baseload generation to provide reliable power at all times. This indicates the potential for some type of LNG-fueled solution to CUC's needs; the evaluation of such LNG potential is another key consideration for this IRP.

CUC's Financial Condition

Years of significant deterioration in the CNMI economy has resulted in CUC realizing materially decreased sales. The cost of fuel is passed through to CUC's customers through a system of fuel surcharges, so CUC does not incur losses on fuel costs with lower sales. However, the fixed operation and maintenance (O&M) costs of CUC's generation, distribution, and administrative functions are recovered through CUC's base rates, which are set assuming certain levels of sales. When fewer sales occur, CUC under recovers its fixed costs. Further, CUC has several commercial and governmental customer accounts, which are significantly in arrears, leaving CUC with several million dollars in accounts receivable. These factors have led to a downgrading of CUC's credit ratings, making it difficult and expensive to obtain the financing necessary to develop new generating facilities.

Section 3
ASSUMPTIONS DEVELOPMENT

An important part of the IRP process is the development of assumptions, which drive scenario development, and the production cost modeling effort that will ultimately quantify costs under each scenario. This Section summarizes the key assumptions developed in a collaborative effort between CUC and Leidos. Additional detail, including a comprehensive list of assumptions, can be found in the separate Assumptions Document, which is included in this report as Appendix A, which was prepared by Leidos and reviewed by CUC in an iterative process to codify assumptions in a transparent process prior to the production cost modeling portion of the IRP study.

Assumptions relating to existing resources, fuel price forecasts, and financial details were developed concurrently with the Energy Supply RFP process, which yielded a selection of candidate resources that are also summarized in this Section.

Study Period

Based on discussions with CUC, the IRP was executed over a 25-year study period over 2016-2040. Projections of CUC load, fuel prices, and other key cost estimates required to perform the screening and production cost modeling were prepared over this same timeframe.

Financial Inputs and Escalation Factors

Based on discussions and input from CUC, the following assumptions were used for general inflation and CUC's cost of capital.

CUC does not have an island-specific view regarding inflationary expectations. While data on consumer price index (CPI) metrics has been collected by Leidos from the Department of Commerce (DOC), this data does not include a projection of inflation. CUC directed Leidos to utilize an inflation assumption consistent with that used for similar project work conducted for Guam Power Authority (GPA). Consequently, Leidos used an inflation assumption of 3.3 percent per year based on Moody's projection of the CPI-based inflation rate on Guam over the period 2014-2035.

With regard to CUC's cost of capital, a similar approach was taken. The cost of capital was assumed to be 5 percent per year, consistent with recent bonds issued for Guam.

CUC Load Forecast and Hourly Load Shapes

The CUC Load Forecast for each island has been prepared using a combination of (i) detailed econometric analysis to project "organic" retail sales across each of the three independent islands and (ii) a separate discrete load additions model that tracks all anticipated hotel and casino load additions (either due to new construction or as a result of anticipated returns to grid service by customers who qualify for CUC's incentive rate), assigns them to one of the islands, and estimates the incremental impact on energy and peak demand. A brief summary of each method is provided below. A full description of each method is available in the Assumptions Document.

Detailed Econometric Analysis

This analysis was conducted using monthly retail sales data provided by CUC's rate consultant over the period of October 2005 – April 2014 for each island. Retail classes modeled include the residential, commercial, and governmental classes. Given the disproportionate influence of Saipan on the total system, as well as the fact that each island is an independent system, detailed econometric analysis was performed for the Saipan retail classes, with the other two islands' sales projected based on relational models that are dependent upon the Saipan forecast.

Explanatory variables including size of the residential customer, CNMI real GDP, hotel occupancy rates, heating and cooling degree days, numerous CPI indices, indicators that track minimum wage levels, and native statistics on arrivals, were investigated for their efficacy in explaining historical variation in Saipan load levels. A detailed discussion of the econometric analysis and the use of specific explanatory variables is included in Appendix A of this report.

Discrete Load Additions

Leidos developed a detailed discrete load characterization model that captures the estimated energy and peak demand impacts associated with the potential hotel/casino loads that may reconnect to the grid (incentive loads) and/or be built based on detailed discussions with CUC and its rate consultant. Two discrete load cases were developed:

- Base Case – The estimated impact associated with loads considered to be "firm," or known load additions only.
- High Case – Given the rather large spread between known load additions and speculative load additions, the High Case reflects all incentive loads returning to grid service and all hotel loads active at 25 percent of their quoted energy and demand levels. The High Case reflects a conservative cap on nominal load levels that assumes a 1-in-4 likelihood for any new hotel load to actually materialize. The High Case reflects a demand increase of as much as 25 MW in aggregate by the end of the study period relative to projected "organic" load growth.

Loss Factors

Following the completion of the econometric analysis by island, it was necessary to estimate a loss percentage to capture the differential between retail sales and actual energy delivered for each island. As described in detail in the Assumptions Document, Leidos conducted a historical loss percentage analysis based on multiple sources to develop loss factors by island. The resulting loss factors assumed for load forecasting, which were applied to the retail sales forecast to derive total energy requirements, were as follows:

Table 3-1
CUC Loss Factors by Island

Saipan	16.37%
Tinian	15.61%
Rota	19.00%

The Base Case and High Case Load Forecasts for Saipan are summarized in Figures 3.1 and 3.2, as well as in Appendix A. Appendix A also shows the Base Case load forecast without the inclusion of any discrete loads for reference purposes (which reflects only organic growth projected econometrically). Tinian and Rota Base Case and High Case load forecasts are also provided in Appendix A.

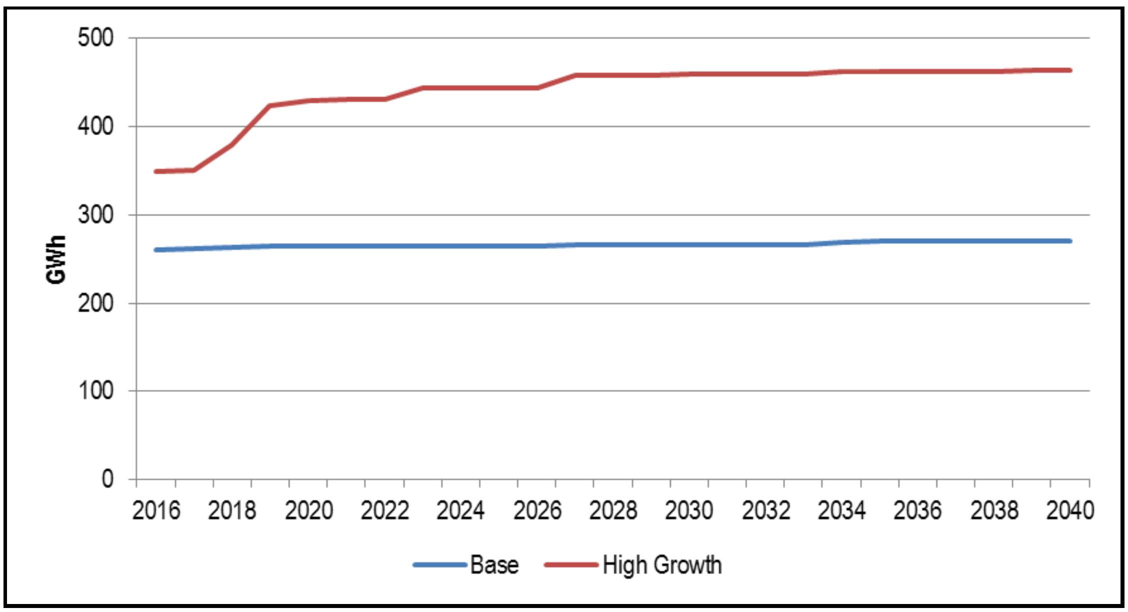


Figure 3.1: Saipan Base and High Energy Requirements Forecasts shown in gigawatt-hours (GWh)

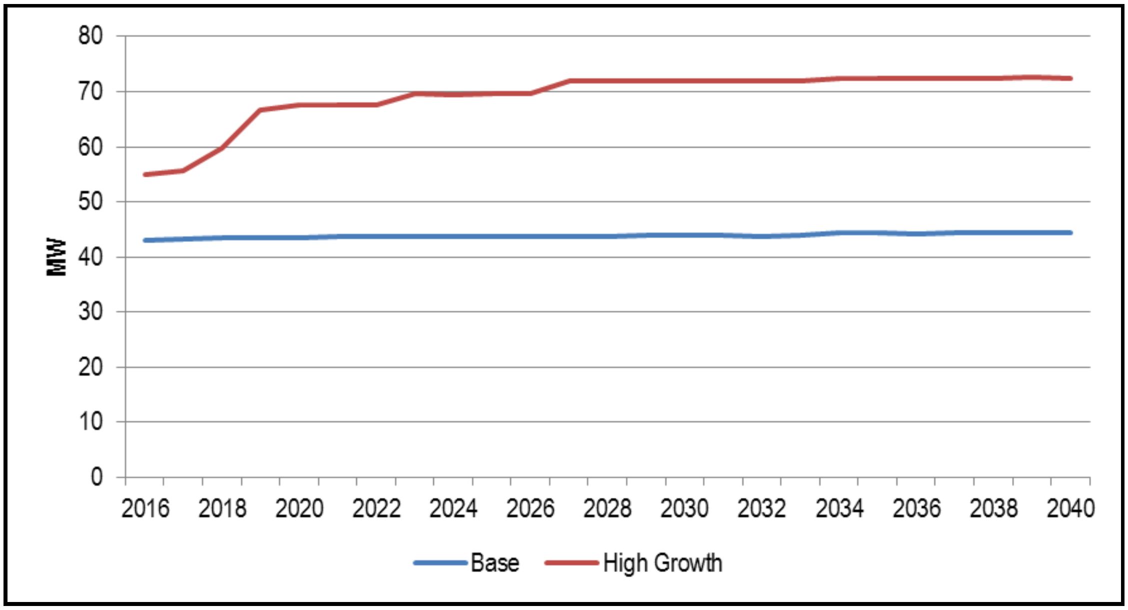


Figure 3.2: Saipan Base and High Demand Forecasts (MW)

Hourly Load Shapes

Hourly load shapes are typically developed using a Typical Meteorological Year (TMY) for the purposes of the IRP assumptions. Limited amounts of historical hourly load data were available for CUC, making the development of a TMY load shape impossible. A full calendar year (2014) of hourly generation data for Power Plant 1 and Power Plant 4 on Saipan was provided by CUC and compiled by Leidos to use as the hourly load profile in the production cost modeling simulations. Hourly load and generation data was not available for Tinian or Rota; therefore, the 2014 shape from Saipan was used in the production cost modeling as the annual load shape for all years of the IRP study period for each island. Given the relatively bounded volatility of weather as a function of temperature swings within the CNMI, the impact of this limitation on hourly simulations has been assumed to be limited

Capacity Reserve Margin

Following the decline in electricity demand since 2005, CUC's three systems have large capacity reserve margins (i.e., are significantly long on existing generating capacity). Originally, as described in Appendix A of this report, the planning capacity reserve margin was to be a 100 percent reserve margin. However, based on subsequent discussions with CUC, the IRP reserve margin was based on the assumption that CUC must maintain sufficient resources to ensure a Loss of Load Probability (LOLP) of one hour in 10 years. This LOLP is based on the combination of projected planned and forced outages of CUC's existing asset base. As a function of bids received in response to the Energy Supply RFP, it became necessary to increase the projected new capacity additions to ensure the target LOLP as Power Plant 1, and eventually Power Plant 4, are retired from service.

Fuel Forecasts

The IRP requires annual fuel price projections for the primary fuel type consumed by the existing diesel generating units that produce power for CUC, No. 2 Fuel Oil (or LFO), as well as the lubricating oil consumed in each diesel unit. Additionally, based on input from CUC and the results of the stakeholder process, a heavy fuel oil (HFO) scenario was desired to be evaluated, as well as a scenario involving LNG. Leidos developed all-in delivered fuel price forecasts for each fuel by forecasting the underlying commodity price and then including island-specific delivery charges, as described below.

Commodity Price Projections

Leidos prepared a delivered commodity price projection for all three fuels, generally based on a blend of short- to medium-term futures information and the Energy Information Administration (EIA) 2015 Annual Energy Outlook (AEO), which provides long-range commodity projections of all key fuels. The commodity cases were used to forecast long-range commodity prices under the AEO cases listed below using assumed Saipan inflation (3.3 percent). For the HFO projection, Leidos selected a sulfur content that has been determined to be least likely to be subjected to environmental compliance challenges (or 0.3 percent sulfur content). Fuel content for LFO and HFO were assumed to be 5.76 and 6.287 million British thermal units (MMBtu) per barrel. The AEO cases considered and summarized in Appendix A of this document are as follows:

- Base Case
- High Oil Price Case
- Low Oil Price Case
- High Resource Case – high supply case which generally reflects lower prices

The LNG forecast required additional adders to the AEO projections related to bulk delivery of LNG to Saipan (with ISO container delivery to Tinian and Rota as described in the Future CUC Resource Options subsection below), which were estimated by Leidos. These adders included allocations for transportation charges, a transportation fuel retention percentage, and liquefaction tolling charges, and shipping charges.

Delivery Charges

Information on existing baseline costs by island was derived from the Levelized Energy Adjustment Clause (LEAC) spreadsheet provided by CUC’s rate consultant. This spreadsheet model compartmentalizes existing commodity costs from other key fees that impact delivery to Saipan, Tinian, and Rota for LFO fuel. Costs delineated in the spreadsheet include shipping and fixed add-on costs, as well as warfage fees, an oil spill tax, a beautification tax, and a gross receipts tax. This information formed the basis for benchmarking existing commodity costs and for determination of the adders and taxes to apply to each future year of the Leidos commodity forecast to arrive at landed (or delivered prices) for oil.

The delivered fuel forecast for each fuel was then prepared by combining the adders and taxes applicable to each fuel with the commodity projection for each AEO case over the course of the study period. The figures below show the annual Base Case forecasts for each commodity by island through the study period.

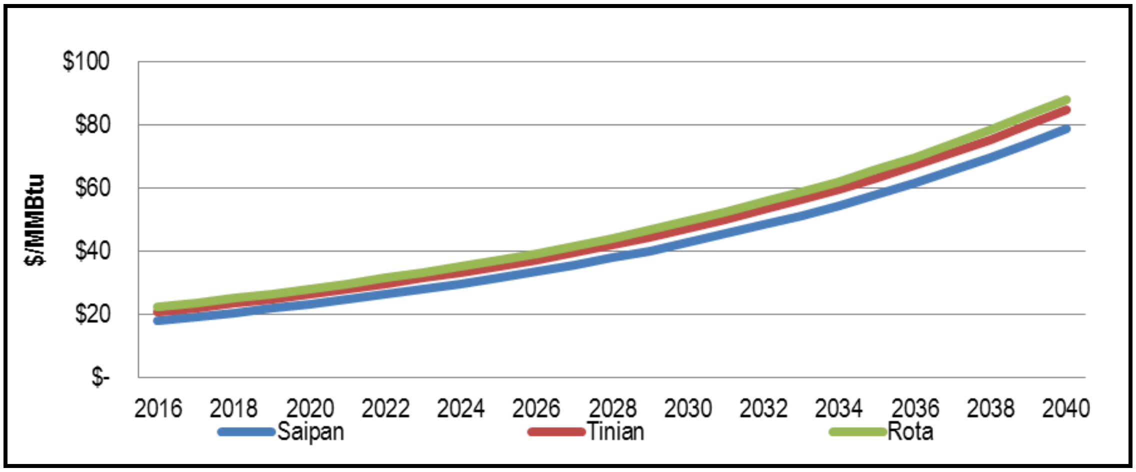


Figure 3.3: Base Case LFO Price Forecast

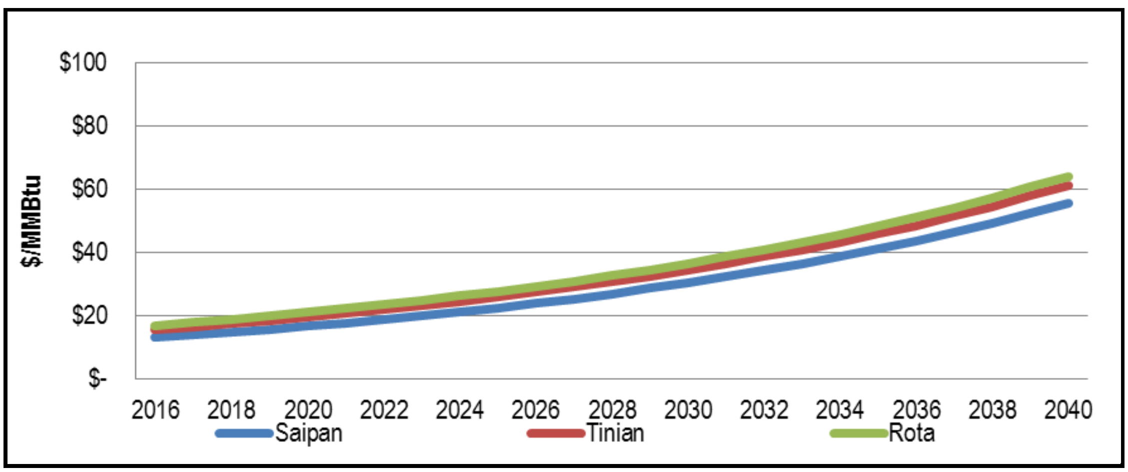


Figure 3.4: Base Case HFO Price Forecast

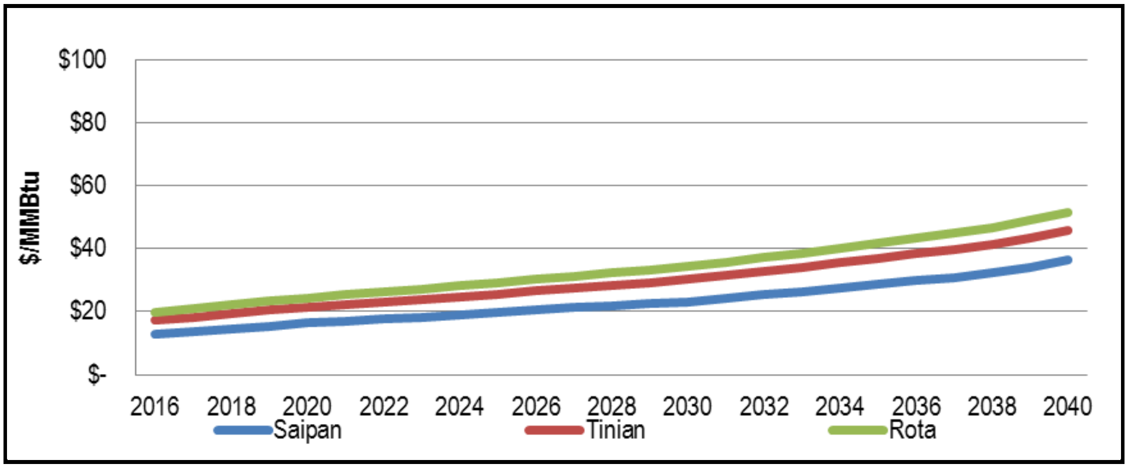


Figure 3.5: Base Case LNG Price Forecast

Lubricating Oil

The diesel generating units operated by both CUC and Telesource on Tinian consume varying quantities of lubricating oil. Lubricating oil costs are included in the CUC fuel adjustment clause, and have been included in the overall operating cost projection for existing and future resources as based on the LEAC data. Growth in lube oil cost has been tied to the growth in the core commodity component of the existing fuel oil used by CUC. Appendix A provides a tabularized summary of lube oil costs in dollars per gallon for Saipan and Rota across each of the fuel cases noted above (using the 3.3 percent inflation rate assumption). Note that because the Tinian assets are subject to power purchase agreement charges outside of fuel, lubricating oil costs are included in the variable O&M costs in Appendix A for Tinian units.

HFO Compliance Costs

In addition to the cost of HFO as a fuel, there are potentially significant environmental compliance costs associated with burning HFO. Leidos has performed a planning-level review of the implications of the EPA regulations with regard to getting permitted for use of HFO. Our review included discussions with NREL, as well as a representative from the EPA. ***While the extent of our review does not in any way constitute a regulatory opinion on the ultimate plausibility of HFO deployment***, it is clear from our review and from the significant stakeholder interest in modeling HFO as part of the IRP that it is reasonable to include such a scenario in the IRP. Note that the HFO scenario includes the construction and operation of an HFO on Saipan only; no capacity additions of any type were projected for either Rota or Tinina. As a consequence of this finding, Leidos has assumed herein that the materiality of the actual act of compliance is secondary to the development of reasonable assumptions that attempt, as best as possible given the limitations inherent in a lack of prior HFO deployment and precedent, to capture the physical compliance technologies and associated cost implications for inclusion in the modeling process.

In order to develop such assumptions, Leidos has interfaced with a vendor that is familiar with existing (legacy) HFO deployments. We have also relied upon our engineering team's suggestions for the engineering and waste stream requirements for deploying HFO.

In order to model the economic implications of an HFO scenario as objectively as possible, Leidos assumed the following additional costs for the HFO bid described above:

- Scrubber/Cooler/Baghouse – estimated cost of $20 million
- Auxiliary power (and associated cost): 1.5 MW per operating hour (based on a system with an induced draft (ID) fan, which is supplanted with cooling water pumps or chillers)
- Increased O&M: $2/MWh
- Increased capital costs associated with compliance: $1 million every three years

Based on discussions with CUC, Leidos did not pursue additional cost estimates for items such as cooling water, lime reagent, source water and disposal costs, and lime commodity, shipping and disposal costs but note that such costs and others will need to be evaluated in the event CUC chooses to pursue an HFO option. Further, it is also likely that additional on-island fuel handling facilities such as pipelines and storage tanks will be necessary to accommodate HFO. These potential additional facilities were also not included in the HFO bid cost estimates.

Existing CUC Generating Assets by Island

CUC was the primary source for CUC's unit characteristics, which are summarized at a high level in the table below. Leidos has performed a review of these characteristics to identify potential areas of concern or anomalies relative to performance characteristics for similar units with which we are familiar, and we have worked with CUC and CUC's rate consultant to obtain additional data and make certain adjustments, as appropriate. Appendix A contains the detailed operating assumptions for each CUC generating unit by island used in the production cost modeling. Table 3-2 provides a brief summary of the existing units that were modeled during the IRP process.

Table 3-2
Current CUC Generation Supply

Plant	Unit	In-Service Year	Firm Capacity (MW)	Unit Type	Status	Heat Rate (MMBtu/ MWh)	Fuel Type
Power Plant 1	1	1979	5.5	Reciprocating	Operating	9.177	No. 2 Oil
Power Plant 1	2	1979	5.5	Reciprocating	Operating	9.150	No. 2 Oil
Power Plant 1	3	1979	5.5	Reciprocating	Operating	9.402	No. 2 Oil
Power Plant 1	4	1983	5.5	Reciprocating	Operating	9.243	No. 2 Oil
Power Plant 1	5	1989	10.0	Reciprocating	Operating	9.337	No. 2 Oil
Power Plant 1	6	1989	10.0	Reciprocating	Operating	9.431	No. 2 Oil
Power Plant 1	7	1991	10.0	Reciprocating	Operating	9.237	No. 2 Oil
Power Plant 1	8	1991	10.0	Reciprocating	Operating	9.295	No. 2 Oil
Power Plant 2	1	1972	1.9	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 2	2	1972	1.9	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 2	3	1972	1.9	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 2	4	1976	1.9	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 2	5	1976	1.9	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	2	1957	2.1	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	3	1956	2.1	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	4	1972	2.3	Reciprocating	Standby	9.746	No. 2 Oil
Power Plant 4	5	1977	2.3	Reciprocating	Standby	9.746	No. 2 Oil
Power Plant 4	7	1998	0.95	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	9	1998	0.95	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	10	1980	2.3	Reciprocating	Standby	9.746	No. 2 Oil
Rota	1	NA	2.3	Reciprocating	Standby	10.10	No. 2 Oil
Rota	3	1998	2.3	Reciprocating	Standby	11.10	No. 2 Oil
Rota	4	1998	2.3	Reciprocating	Standby	11.10	No. 2 Oil
Rota	5	2010	2.3	Reciprocating	Standby	9.80	No. 2 Oil
Rota	6	2010	2.3	Reciprocating	Operating	9.80	No. 2 Oil
Tinian	1		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	2		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	3		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	4		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	5		4.5	Reciprocating	Operating	97.46	No. 2 Oil
Tinian	6		4.5	Reciprocating	Operating	9.746	No. 2 Oil

Future CUC Resource Options (Supply-Side)

Future resource options available to CUC have been derived from the following three sources:

- Detailed RFP responses by individual bidders, which include cost, performance, and transactional details for a range of generating resources; the RFP responses have been subjected to a detailed and rigorous qualification process, after which a subset of the bids was deemed qualified for further evaluation. The domain of resources for the bids that were qualified include solar generation, energy storage, traditional diesel-fired generation deploying both LFO and HFO, and a major maintenance project related to CUC's existing generating units.
- A review of the most practical DSM options available to CUC for endorsement as based on Leidos' review of available information – as there were no bids received that contained DSM. The DSM Portfolio Definition subsection in Appendix A represents the entirety of programs that were screened and considered for the IRP.
- An LNG-based solution as an additional option that was to be parameterized based on cost estimates compiled by Leidos.

Table 3-3 summarizes the bids received in response to the RFP. All of the detailed cost and performance assumptions and the terms associated with each option (i.e., the number of years assumed for modeling the specific transaction) across each of the bids (some of which contain more than one specific option or technical solution) is contained within Appendix D of the Assumptions Document and should be referred to as a supplement to the descriptions herein. For confidentiality purposes, the names of bidders have been removed, and each bid is defined with a bidder number in order to facilitate review of this document without disclosure of bidder identities.

It is important to note that other potential supply-side resource options and renewable options that did not receive any specific RFP bids and/or have been determined to be infeasible on Saipan due to the size of the load on each island and other factors, including resources such as biomass, waste-to-energy, coal-fired generation, hydroelectric generation, nuclear generation, geothermal generation, and wind generation are not considered further herein. It should be noted that the LNG assumptions delineated herein and in Appendix A are not associated with a specific bid and should be interpreted accordingly.

Table 3-3 summarizes the qualified bids received that formed the basis of the scenarios, screening analysis, and ultimate production cost simulations. As noted above, bidders are masked.

Table 3-3
Qualified Energy Supply Bids

Bidder	Generating Resource Type/Description	Maximum Capacity Offered
Renewable 1	A range of solar PV generation, both with and without battery storage and including optionality with regard to site control at specific feeders	Range of bids covers 1 MW-$_{AC}$ up to 10 MW-$_{AC}$[1]
Renewable 2	Solar PV generation only	10 MW-$_{AC}$
Thermal 1	Traditional diesel generation running on HFO as a single project (all capacity added at once)[2]	30 MW (nominal rating of asset proposed); reflects installation of four diesel units with a nominal rating of 8.73 MW each
Thermal 2	Traditional diesel generation running on LFO as a single project (all capacity added at once)	Four diesel units, each with a nominal rating of 8.73 MW
Thermal 3	A range of remediation of CUC's existing asset base and new diesel generation running on LFO, with pricing based on three alternative solutions[3].	Alternative Solution A: installation of four diesel units with a nominal rating of 8.7 MW on a fast-track basis, with additional allowance for two more units at CUC's discretion Alternative Solution B: 70 MW (nominal rating of powerhouse with additional capacity expansion relative to Alternative Solution 2); still based on increments of 8.7 MW with a maximum expansion of 12 units

Following is a description of the transactional nature of each of the above bids, which served as the basis for modeling each bid. It is critical to note that the ultimate transactional details of a given option will be subject to downstream negotiations between CUC and a given bidder to the extent a bid is determined to be economical and in alignment with the IRP objectives, the details of which cannot be foreseen at this time and which fall outside the scope of the IRP. Additionally, certain bidders have made site-specific assumptions within their pricing, while others have not and have provided site-neutral pricing that assumes a standard or minimal amount of site remediation, property taxes, and/or leasing costs. ***However, it was assumed that each bidder intends to remain in alignment with their proposed terms and conditions as well as their pricing as a foundation for successful project deployment and contractual negotiations, and the modeling performed during the IRP has been predicated on this assumption (i.e., that the bidder pricing includes embedded***

[1] "$_{AC}$" denotes alternating current capacity.

[2] Inquiries to bidders were made regarding the possibility of a more gradual increase in capacity. However, bidders' responses indicated that such a configuration would generally be more expensive given the additional soft costs associated with gradual installation, and consequently, certain bidder responses reflect "all-in" capacity projects.

[3] A fourth alternative solution was proposed but then retracted by this bidder due to lack of cost information.

charges that reflect some amount of execution risk on the part of the bidder related to unforeseen conditions, exclusions of project envelope elements, and other deployment nuances that will be pursued if and only if CUC determines to move forward with a given bidder).

Renewable 1

This bid proposed a long-term PPA with CUC for a term of up to 25 years with no cash contribution required on the part of CUC. Renewable 1 would finance, construct, and operate the project in whichever configuration and combination of capacity, storage, and site control desired, and would charge CUC a set rate per MWh of energy delivered with a 1 percent annual escalation of the rate. All costs associated with the project would be paid by the developer and decommissioning would also performed by the developer. Costs differ to some extent as a function of the amount of capacity and configuration selected. Refer to Appendix D of the Assumptions Document for further details. *The cost of storage for ramp rate control was provided for one bid and stated to be scalable to all other bids. Additional costs for energy storage were included in the production cost modeling and screening analysis as necessary.*

Renewable 2

This bid proposed a PPA with a term of up to 25 years at a set price per MWh of energy delivered, with 0 percent annual escalation. Pricing is provided both with and without the benefits of federal investment tax credits (ITC) and certain depreciation benefits. The lower tier of pricing is contingent upon completion of construction by December 31, 2016. Both prices reflect 0 percent annual escalation and no cash contribution on the part of CUC. The developer would finance, construct, and operate the facility and charge CUC on the basis of the PPA. *It is important to note that as part of bidder follow-up, it was determined that the cost of storage for ramp rate control for the amount of capacity bid into the system was quoted to reflect a 10 percent increase in the indicative PPA pricing provided by this bidder.*

Thermal 1

This bid proposed a bidder constructed, financed and operated plant (through the use of an O&M firm), which is assumed to operate over the entire study period based on extension of the PPA proposed. Charges would be recovered as a function of an independent power producer (IPP) structure wherein the bidder would recover charges associated with the facility, including (i) capacity charges that capture debt service and fixed O&M charges and (ii) variable O&M charges outside of fuel. Capacity and fixed O&M charges were obtained via bidder follow-up based on both a 15-year and 25-year arrangement, and both were considered as part of the screening analysis. Capacity and variable charges would be subjected to 2.3175 percent escalation annually. CUC is responsible for providing fuel to the plant. Additionally, as the bidder did not adequately capture the cost of environmental compliance associated with the proposed fuel, Leidos estimated the additional capital cost associated with equipment and environmental compliance activities (as described above) and added those estimates into the modeling for this bid.

Thermal 2

This bid was based on an EPC process to develop the project, and a follow-on O&M arrangement that would allow the bidder to operate the plant over the entire study period. In this configuration, financing of the project would be dependent upon CUC, and the bidder would serve solely in an O&M capacity, with associated fixed and variable charges to recover operational costs. Fuel delivery would be based on CUC fuel delivery to the project. The bidder has provided terms and conditions associated with the O&M contract that reflect escalation rates on such charges equal to one percent over and above the prior year’s U.S. GDP Implicit Price Deflator (US GDPIPD).

Thermal 3

This bid proposed multiple alternatives for future capacity and major maintenance. Each solution that was carried forward into the modeling (which excluded Alternative 1 due to lack of cost data and Alternative 4 due to it being withdrawn by the bidder) is dependent upon (i) a capacity charge that reflects recovery of the debt service costs of the solution (bid in as a monthly charge over the proposed financing period of 20 years, which will go to zero over the remaining study period years), (ii) charges intended to cover other fixed O&M charges, and (iii) variable O&M charges. As with all other thermal solutions, fuel delivery would be the responsibility of CUC. Cost escalation rates for charges are based on 1.5 percent over and above the prior year’s US GDPIPD, beginning with the second year of billing. The ultimate financing of a given alternative is ostensibly based on bidder financing; however, the financing of a given alternative is also based on securitization and guarantees by CUC and/or the government; for IRP modeling purposes, it was assumed that the financing will take place and that the bidder will serve in an IPP capacity, collecting charges commensurate with the capital cost, fixed and variable cost associated with the project.

LNG Option Assumptions

As noted above, there were no bids received that included LNG as an option. Given that LNG was determined to be of interest to IRP stakeholders, as has been done with the proposed demand-side management portfolio, Leidos prepared planning level assumptions for an LNG centric solution. These assumptions are summarized in Appendix A. The bullets that follow describe the core elements of the proposed LNG solution:

- LNG would be delivered in bulk to Saipan, which requires a dedicated LNG facility to be built on the island. Regasification and shipment to Tinian and Rota, to the extent such islands can support the scale of load that is commensurate with gas-fired or dual-fuel generation, which based on Leidos’ review is tractable given the size of units that could be constructed, would be based on ISO container delivery.

- Under the assumption that the existing CUC fleet is prohibitively old to consider a conversion to gas, new dual-fuel capacity for Saipan would be constructed in addition to the LNG facility.
- The capital cost of the LNG facility would be an added cost, over and above fuel delivery and the capital cost of the new gas-fired resources as part of an integrated solution that assumes that CUC would derive the majority of their thermal resource needs from gas (i.e., that there would be limited to no remaining LFO used across the islands). Given the terms and conditions of the existing Tinian PPA, it is unlikely that LFO use would be eliminated entirely over the study period, and Leidos modeled the costs associated with the Tinian PPA and the associated obligations for the "all-in" LNG deployment case. However, the deployment of LNG is only plausible as a function of a certain baseline of fuel demand that would hypothetically provide sufficient incentive for developers to commit to the infrastructure required. Leidos estimated the annual fuel requirements as a function of the capital cost estimate for fuel infrastructure associated with this potential solution.
- As an added illustrative scenario relative to the "all-in" transition to LNG as described above, Leidos also prepared a scenario that only encompasses a transition for Saipan (with a proportional reduction in fuel infrastructure capital cost), with the understanding that such a scenario could have certain implications relative to the impact on fuel-oil pricing and delivery to Tinian and Rota, the estimates of which fall outside the scope of this IRP.

Renewable Resources

Generation from PV resources is highly dependent on when the sun is shining and others factors such as cloud cover. This makes PV resources fundamentally different than conventional, dispatchable resources when developing capacity expansion plans. PV resources provide energy but at capacity factors lower than conventional resources and at times that are dependent on the solar resource, rather than being scheduled to meet energy requirements.

For planning purposes, hourly generation profiles provided by PV bidders and based upon PVSyst were used in IRP modeling. The hourly profiles used in the IRP represent capacity factors of 22 percent to 25 percent (measured on an AC basis) and are fixed for the IRP study period. As a result, over the course of one year the modeled average output of the plant will be 25 percent or less of the rated capacity of the plant since the plant only generates electricity during daylight hours and operates at or near its maximum capacity only during the solar peak of the day.

In addition, the PV plant output cannot be scheduled (dispatched) without storage, except to turn down the generation. Significantly, this means that a PV resource typically does not generate at its maximum capacity during peak system loads. A given quantity of PV capacity will not be able to provide the same level of reliability at peak hours as a dispatchable resource. As shown in Figure 3.6, the peak demand hour may occur after the peak hour of PV generation. In this case, the PV plant does not contribute its full capacity to meeting peak demand.

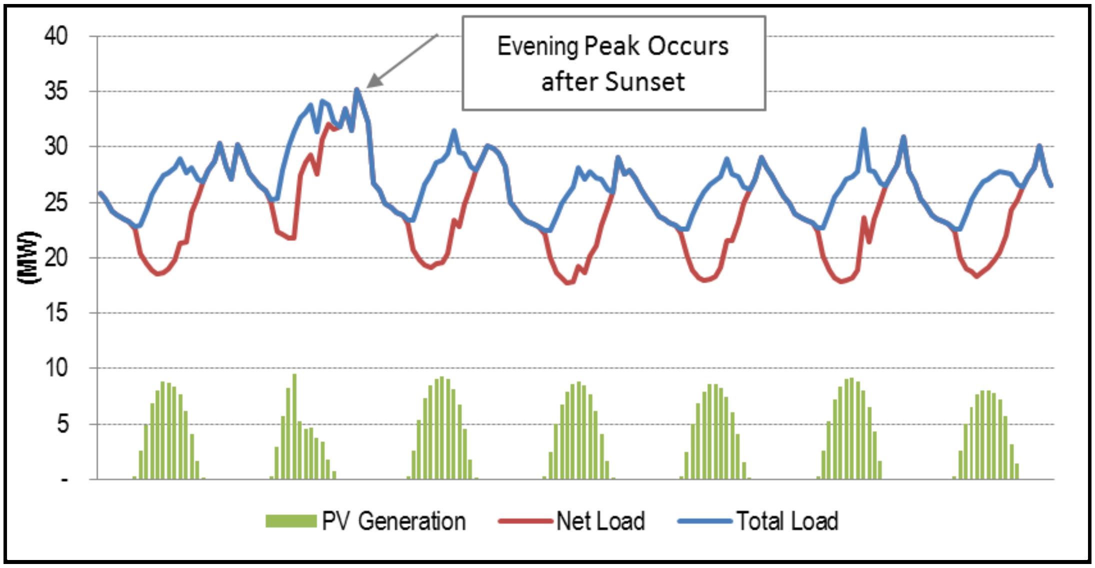


Figure 3.6: Sample Hourly Load vs. PV Generation (typical data used for illustration; not specific to any PV bid)

Only a portion of nominal PV capacity can be expected to be coincident with peak demand. This issue is accounted for in the expansion planning process by reducing to the nameplate capacity to a level that results in a "peak" or "firm" capacity that is expected to be available during all peak hours. The assumption used in the IRP is that "firm" PV capacity is 25 percent of its nameplate value based on an analysis of hourly PV generation and hourly demand. Figure 3.7 shows the top 25 load hours of a typical year with and without 10 $MW\text{-}_{AC}$ of PV. The annual net peak (hour 1 in the figure) is approximately 2.5 $MW\text{-}_{AC}$ below the peak load without PV; therefore, 25 percent of the nameplate capacity for a 10 $MW\text{-}_{AC}$ PV plant is expected to be available for the annual peak. When adding resources a given IRP scenario, 25 percent of the PV nameplate capacity ($MW\text{-}_{AC}$) is used to calculate the firm capacity of that scenario.

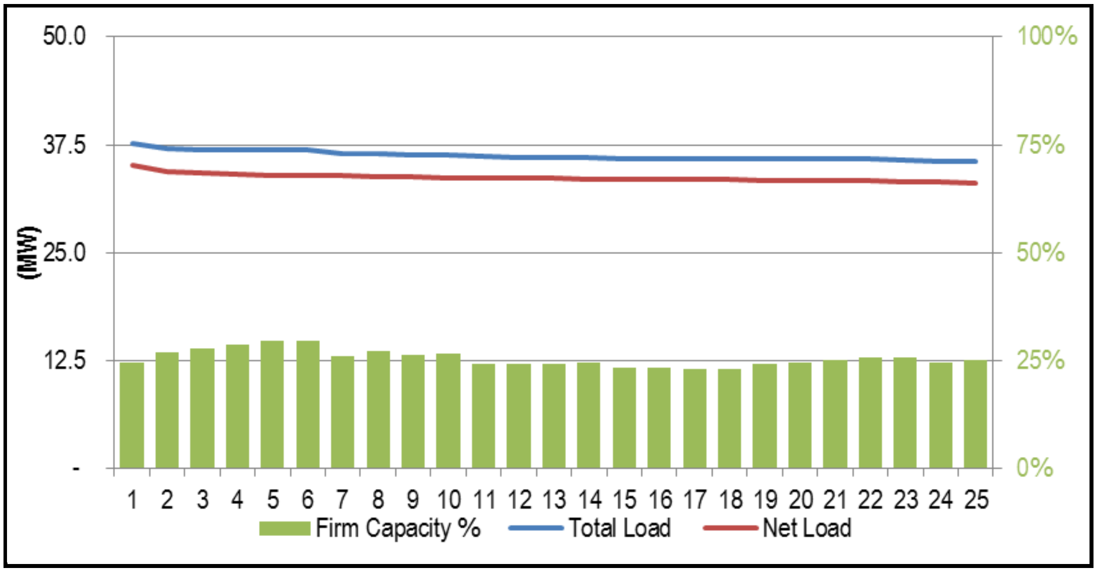


Figure 3.7: CUC Base and High Peak Forecasts (MW)

Distributed Generation

Distributed PV installations that have the potential to reduce future load to be served by CUC were parameterized separately. Often, but not always installed on residential and commercial rooftops, distributed PV effectively reduces demand that must be served by CUC and can, therefore, be considered a load modifier. In order to project the effects of distributed PV independently of the load forecast, separate distributed PV uptake forecasts were developed.

Leidos discussed the outlook for increased penetration of distributed PV with both CUC and the NREL representative for the IRP. Based on those discussions, Leidos incorporated several commercial scale PV installations into the PV adoption forecasts in addition to a diffusion based adoption curve developed by Leidos. Two distributed PV adoption scenarios were developed for use in sensitivity cases:

- Base Adoption Case – half of the commercial scale installations discussed with CUC and NREL become operational
- High Adoption Case – all commercial scale installations become operational

Distribution System Costs

Leidos assumed that costs for distribution system impact analysis and any distribution system upgrade costs associated with a particular deployment option that involves new resource types is the responsibility of the RFP bidder to provide as part of their response. Additionally, CUC owns and maintains an existing distribution system model that can be used to perform power flow and stability analyses, and there are dedicated CUC personnel that will be made available to perform those studies as part of any potential bidder negotiations. Additionally, CUC has provided an existing study regarding renewable integration that contains framing information regarding potential distribution system impacts for a given installation. These resources were leveraged on a bid-by-bid basis to ensure that an adequate accounting of any distribution system costs is included in the total cost of a given bid.

Demand-Side Management Options and Portfolio Definition

DSM options, which include energy efficiency (EE), demand response (DR), conservation, and other behavioral programs, were considered in parallel with traditional supply-side resource options in an integrated and holistic fashion. None of the bids received reflected any DSM. Therefore, the following roadmap was followed to ensure that DSM was treated fairly and transparently within the IRP:

- EE programs are a requirement of Senate Bill 15-38. Since there were no bids received that reflected DSM, there was no need to examine bids to determine the extent to which they support compliance with Senate Bill 15-38. Additionally, Senate Bill 15-38 was deemed "not determinative" in terms of the evaluation of a given program, the assumptions for which have been based on planning-level DSM investigations conducted by Leidos.
- Given that compliance with the legislation is not a specific requirement, Leidos performed a high-level DSM screening using our proprietary DSM decision-making model, and selected only those DSM measures that are economical based primarily on the TRC cost-benefit framework, which is an industry-standard metrics for determining the economic competitiveness of a given DSM portfolio element, which then determined the ultimate inclusion (or lack thereof) of a given DSM portfolio element. The DSM measures that were investigated for purposes of the screening are discussed in the DSM Portfolio Definition subsection below.
- The load (energy and peak demand) impacts of any DSM measure deemed economical and worthy of deployment was modeled as a reduction to the load forecast prior to the onset of production cost modeling. The cost associated with the DSM portfolio (all included DSM measures) was then added as a line item to the production cost simulations associated with serving the remaining grid load.

DSM Portfolio Definition

As part of the IRP, Leidos was tasked with evaluating a targeted set of energy efficiency programs that represent "low hanging fruit" in terms of economic potential and impact on Saipan and CNMI energy consumption. Specifically, the Leidos review focused on defining representative, simple programs for each of the residential and commercial sectors that have a high probability of success, are low cost, and will motivate customer interest in further energy efficiency measures. As noted above, these initial programs were subjected to a DSM screening. To the extent such screening resulted in a positive estimated program impact from a cost-benefit perspective, these programs were incorporated into the downstream production cost scenarios, with associated costs added into the overall CUC power supply cost estimates.

After review of available NREL analyses and CUC information about CNMI energy consumption, Leidos recommended an initial set of programs for residential and commercial customers with the following characteristics:

- A residential program that emphasizes easy, self-installation of water and lighting measures distributed via a free kit.
- A commercial program that addresses significant energy end uses for hard to reach small- and medium-sized businesses—lighting and refrigeration measures administered via a 'turnkey' direct install program; energy efficient technologies suited to prescribed energy savings estimates and unit incentives that are clear to the customer and require minimal technical expertise to administer.
- Program delivery approaches that utilize existing equipment distributors, contractors, and other trade allies in the 'midstream' of the market, motivating greater participation and facilitating evolution of programs into more advanced offerings. Targeting the midstream directs outreach and other administrative spending to a limited audience, who can then bring the program information to end-use customers.

Renewable Portfolio Standard Requirements

The RPS outlined in Public Law 15-23, which was signed into law in August 2006, called for fairly aggressive renewable energy targets beginning in 2007 and culminating in 50 percent of net electricity sales coming from renewable sources by 2030.

One year later, in September 2007, Public Law 15-23 was amended with the passing of Public Law 15-87. The amended RPS was significantly increased to require 80 percent of electricity sales from renewable sources by December 31, 2014. Renewable energy targets from both laws have not been achieved.

Public Law 18-62 was subsequently passed in January 2014 and revised the renewable energy targets once more. The current RPS target is now 20 percent of CUC net electricity sales by December 31, 2016. Public Law 18-62 is silent on the RPS requirement beyond 2016. Therefore, a maximum RPS of 20 percent which was not necessarily be prescriptive was assumed for compliance within the study period, with the understanding that higher levels of renewable energy could be possible if justified economically. It is assumed that compliance may be met by aggregating renewable energy across the three CUC systems.

Section 4
SCENARIO DEVELOPMENT

A primary component of the IRP strategy called for the development of a range of IRP scenarios, using information from the stakeholder engagement activities, the Energy Supply RFP, assumptions related to the existing CUC systems, DSM options screening, and engineering estimates related to additional resource options potentially available to CUC. These foundations of the IRP strategy collectively yielded a number of supply-side and demand-side resource options to be considered in the IRP, as described in Sections 1 and 3 of this report. The next phase of the IRP included the development of an LCOE screening analysis, which was used to determine which of those options would be included in the IRP scenarios to be modeled in the final phase, as well as the development of those scenarios.

LCOE Screening Analysis

Prior to the detailed production cost modeling phase of the IRP, Leidos used our internally developed, proprietary screening tool to summarize and evaluate the production costs of energy associated with bids submitted in response to the RFP, as well as the LNG resource option. By performing this analysis in advance of the production cost modeling, the CUC and Leidos IRP teams gained insight into how the Energy Supply RFP bids' costs compared to CUC's current power supply costs.

The screening evaluated capital, operating expenses (fixed and variable), fuel, and other costs (if any) for each of the resource options (including renewable options), and then estimated the all-in $/MWh cost of each resource for a range of plausible capacity factors.

In parallel with the LCOE analysis, a series of residential and commercial DSM programs were parameterized and evaluated, primarily using the TRC test benefit-cost ratio. As a result of the strong performance of such measures under the TRC framework, said measures were assumed as being endorsed and modeled via a commensurate load forecast reduction (with associated measure costs included) as part of the downstream IRP scenario modeling.

The LCOE analysis and parallel DSM screening yielded a number of initial findings related to the comparative economics of the energy supply options available to CUC, including:

1. The potential DSM options identified for residential and commercial customers are projected to be materially cost effective for CUC and its customers based on the deployment of industry standard benefit-cost ratios, and under the assumption that the TRC Test serves as the basis for endorsement of a particular DSM option.

2. The PV bids received in the Energy Supply RFP are projected to be materially cost effective relative to CUCs existing assets and new, oil fueled assets, which were included in the RFP bids.
3. The LNG options identified by Leidos, using planning-level engineering and cost assumptions, are projected to be significantly less costly than fuel oil options. Further detailed feasibility work will be necessary to refine such estimates and hone in on the potential sources of LNG supply to CUC.
4. The oil fueled options are the most costly options identified in the analysis, and are not projected to have materially different long term costs relative to each other.

Figures 4.1 and 4.2 summarize the results of the LCOE screening analysis.

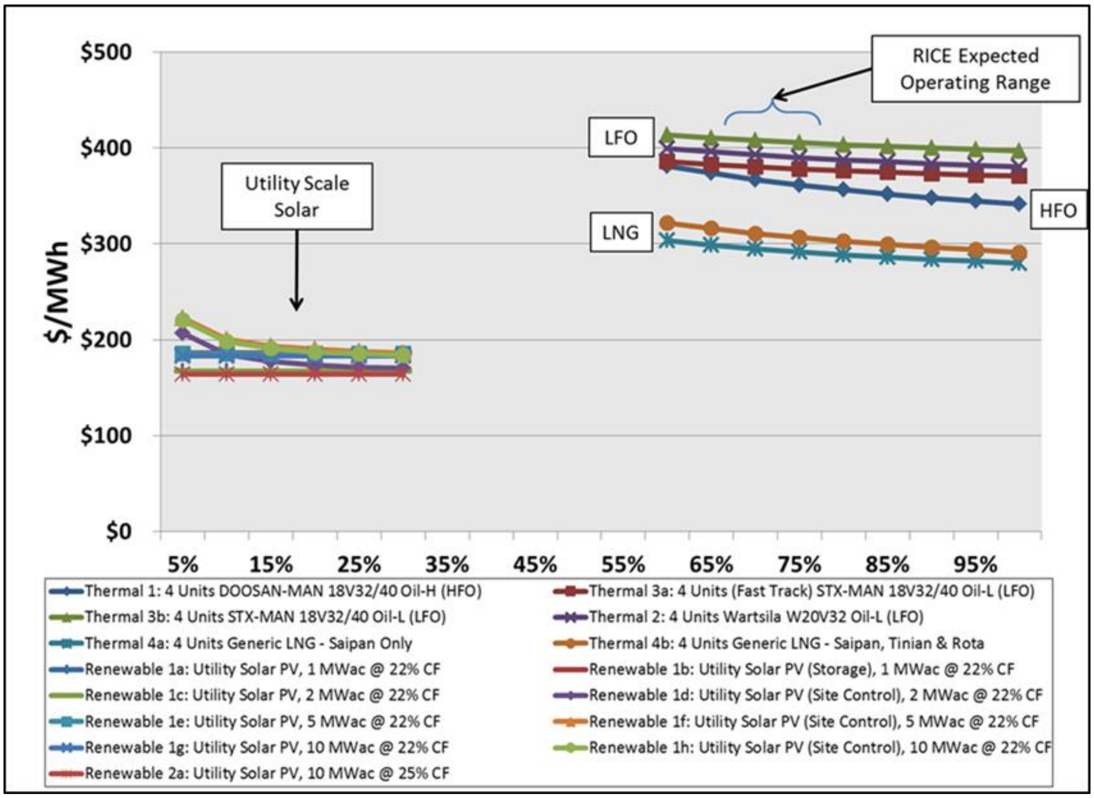


Figure 4.1: LCOE of Qualified Proposals and Resource Options

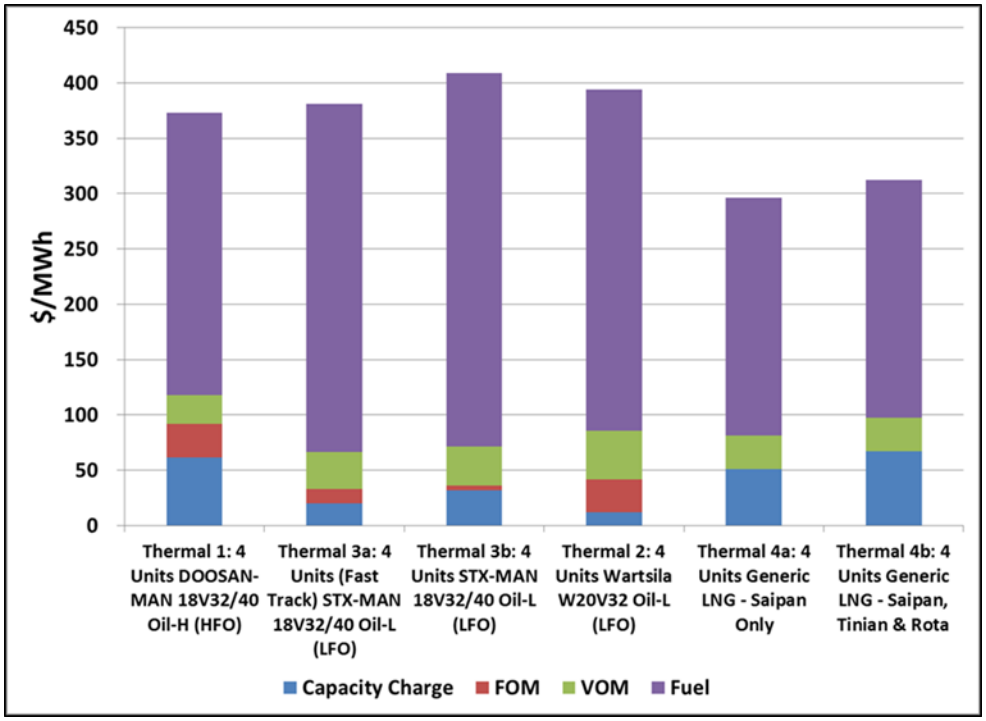


Figure 4.2: LCOE by Component for Thermal Proposals

As a result of the LCOE screening, two redundant technology bids were eliminated from the final phase of the IRP analysis. The Thermal 2 proposal to install diesel-fueled reciprocating engines was identified as the higher cost proposal for diesel-fueled units relative to the Thermal 3 proposal for diesel-fueled reciprocating engines and, thus, was eliminated from further consideration. Similarly, the Renewable 2 PV power proposal was identified as the higher cost PV proposal relative to the Renewable 1 PV proposal, and was also eliminated from further consideration in the final phase.

IRP Scenario Development

The scenarios developed during this portion of the IRP process were dictated by the (i) the bids received during the RFP process and (ii) the desire of CUC to analyze multiple fuel types for future baseload generation alternatives. The IRP modeling scenarios described in this Section were designed to quantify the projected impacts to CUC's future of various combinations of candidate resources available to CUC. Candidate resources include:

- The least cost HFO and LFO bids as determined through the screening process
- The LNG solution estimated by Leidos
- All Solar PV bids received during the RFP process
- The DSM measures suggested in the DSM Portfolio Definition subsection

The candidate resources above were combined into possible futures for detailed production cost modeling and analysis. Cases were developed to evaluate both individual bids received as well as to evaluate combinations of resources that may yield lower cost expansion plans.

Scenario Descriptions

Following is a brief description of the design of each IRP scenario, as well as key assumptions contained in the scenario. The cases are categorized as follows:

- Cases 1 – 5: "base" cases used to evaluate the individual baseload generation alternatives
- Cases 6 – 10: used to evaluate the individual solar PV candidate resource options received during the RFP process
- Cases 11 – 16: "portfolio" cases with combinations of candidate thermal options plus least cost solar PV options
- Cases 17 – 18: Sensitivity cases based on the "portfolio" cases to quantify the impacts of alternative fuel prices and load forecasts

Base Cases 1-10

For ease of comparison, Table 4-1 briefly summarizes the resources that are included in each of the Base Cases. Table 4-1 is followed by more detailed descriptions of each case.

Table 4-1
Base Cases 1 - 10

	Existing Resources				Candidate Resources							
Case	PP1	PP4	Rota	Tinian	Net Energy Metering (NEM) Base	DSM (All)	Thermal 3a	Thermal 1	Thermal 4a	Thermal 4b (Rota)	Thermal 4b (Tinian)	PV (MW$_{\text{-AC}}$)
Case 1, BAU	X	X	X	X	X							
Case 2, LFO Replacement	X		X	X	X	X	X					
Case 3, HFO Replacement		X	X	X	X	X		X				
Case 4, LNG-Saipan		X	X	X	X	X			X			
Case 5, LNG-All		X			X	X			X	X	X	
Case 6, BAU, 1MW$_{\text{-AC}}$ PV1	X		X	X	X	X						1
Case 7, BAU, 2MW$_{\text{-AC}}$ PV1	X		X	X	X	X						2
Case 8, BAU, 5MW$_{\text{-AC}}$ PV1	X		X	X	X	X						5
Case 9, BAU, 10MW$_{\text{-AC}}$ PV1	X		X	X	X	X						10
Case 10, BAU, 10MW$_{\text{-AC}}$ PV2	X		X	X	X	X						10

Case 1: Business as Usual Case

The Business as Usual (BAU) Case serves as the reference case and is used to compare production cost differentials of all other cases. This assumes that CUC can extend the life of the existing asset base through the end of the IRP study period, with associated costs to manufacture parts and engage in other necessary maintenance included in operational cost of the existing asset base.

- **Fuel**: Light Fuel Oil, Base Price Forecast
- **Distributed PV**: Base case distributed PV forecast
- **DSM Resources**: None
- **Candidate Resources**: None

Case 2: LFO Replacement

This case assumes that the least cost LFO candidate resource, as determined through the LCOE screening process, is sited at the existing Power Plant 4 site. A sufficient quantity of backup capacity on Saipan will remain available at Power Plant 1 based on the retirement order agreed upon in Appendix A. In addition, all five DSM programs suggested in the IRP are implemented and associated capacity and energy benefits are realized. Tinian and Rota continue to operate under the BAU case.

- **Fuel**: Light Fuel Oil, Base Price Forecast
- **Distributed PV**: Base case distributed PV forecast
- **DSM Resources**: Five new programs
  - Residential: 1) water savings kit and 2) light emitting diodes (LED) replacement
  - Commercial: 3) LED replacement, 4) Super T8 lamp retrofit, and 5) refrigeration retrofit
- **Candidate Resource Options**: Thermal_3a - LFO reciprocating units

Case 3: HFO Replacement

This case assumed that CUC will retire the existing Power Plant 1 units and rely upon the HFO bid received for future generation. The environmental compliance costs associated with the No. 6 fuel oil bid were not included in the bidder response related to this solution. Consequently, capital costs and other costs associated with environmental compliance for this fuel estimated by Leidos are included as adders to the core bidder costs associated with this case. New generation would be sited at the existing Power Plant 1 site with Power Plant 4 remaining available for backup and operating on LFO. In addition, all five DSM programs suggested in the IRP are implemented and associated capacity and energy benefits are realized. The HFO case assumed that Tinian and Rota continue to operate under the BAU case using LFO.

- **Fuel**: Heavy Fuel Oil (new units) and LFO (Saipan backup units), Base Price Forecast
- **Distributed PV**: Base case distributed PV forecast
- **DSM Resources**: Five new programs
  - Residential: 1) water savings kit and 2) LED replacement
  - Commercial: 3) LED replacement, 4) Super T8 lamp retrofit, and 5) refrigeration retrofit
- **Candidate Resource Options**: Thermal_1 - HFO reciprocating units

Case 4: LNG Replacement – Saipan Only

This case assumes that CUC will retire the existing Power Plant 1 units and rely upon the LNG alternative for Saipan only. This case assumes Tinian and Rota continue to operate under the BAU case using LFO. The planning level LNG alternative developed by Leidos includes new reciprocating generation units as well as the infrastructure described in the Assumptions Section. New generation will be sited at the existing Power Plant 1 site with Power Plant 4 remaining available for backup and operating on LFO. In all LNG replacement scenarios, only LNG-fueled units are evaluated. It is likely that if CUC chooses to pursue an LNG solution, it may wish to pursue dual-fueled (both LNG and LFO) units as part of the LNG solution; this and other specific considerations associated with each case are assumed to be addressed in future implementation studies. In addition, all five DSM programs suggested in the IRP are implemented and associated capacity and energy benefits are realized.

- **Fuel**: LNG (new units) and LFO (Saipan backup units), Base Price Forecast
- **Distributed PV**: Base case distributed PV forecast
- **DSM Resources**: Five new programs
  - Residential: 1) water savings kit and 2) LED replacement
  - Commercial: 3) LED replacement, 4) Super T8 lamp retrofit, and 5) refrigeration retrofit
- **Candidate Resource Options**: Thermal_4a - LNG reciprocating units Saipan

Case 5: LNG Replacement – All Islands

Assumptions for Case 5 are the same as those in Case 4 for Saipan. In addition, this case assumes that the existing units on Tinian and Rota will retire and be replaced by new natural gas reciprocating units. LNG will be supplied the islands via ISO container shipped from Saipan. LNG infrastructure for Tinian and Rota is included in this case. In addition, all five DSM programs suggested in the IRP are implemented and associated capacity and energy benefits are realized.

- **Fuel**: LNG (new units) and LFO (Saipan backup units), Base Price Forecast
- **Distributed PV**: Base case distributed PV forecast

- **DSM Resources**: Five new programs
  - Residential: 1) water savings kit and 2) LED replacement
  - Commercial: 3) LED replacement, 4) Super T8 lamp retrofit, and 5) refrigeration retrofit
- **Candidate Resource Options**: Thermal_4a - LNG reciprocating units Saipan. Thermal_4b – LNG reciprocating units for Tinian and Rota

Cases 6-10: BAU with DSM and PV

Assumptions are the same as those for Case 1 but with the addition of DSM resources and PV candidate resources.

- **Fuel**: Light Fuel Oil, Base Price Forecast
- **Distributed PV**: Base case distributed PV forecast
- **DSM Resources**: Five new programs
  - Residential: 1) water savings kit and 2) LED replacement
  - Commercial: 3) LED replacement, 4) Super T8 lamp retrofit, and 5) refrigeration retrofit
- **Candidate Resource Options (Case 6)**: Renewable_1a – 1 MW-$_{AC}$ solar PV
- **Candidate Resource Options (Case 7)**: Renewable_1c – 2 MW-$_{AC}$ solar PV
- **Candidate Resource Options (Case 8)**: Renewable_1e – 5 MW-$_{AC}$ solar PV
- **Candidate Resource Options (Case 9)**: Renewable_1g – 10 MW-$_{AC}$ solar PV
- **Candidate Resource Options (Case 10)**: Renewable_2a – 10 MW-$_{AC}$ solar PV

"Portfolio" Cases 11 - 16

The following "portfolio" cases are based on Case 2 (LFO), Case 3 (HFO), or Case 5 (LNG-All Islands) and incorporate two capacity levels of the least cost solar PV alternatives evaluated in prior cases. These cases are intended to quantify the cost savings, if any, of adding solar PV resources to baseload fuel alternatives. Table 4-2 below summarizes the resources evaluated in each of the "portfolio" cases.

Table 4-2
"Portfolio" Cases

Case	PV Capacity (MW)	Case 2 (LFO)	Case 3 (HFO)	Case 5 (LNG-All)
Case 11, LFO, 5MW$_{-AC}$ PV	5	X		
Case 12, LFO, 10MW$_{-AC}$ PV	10	X		
Case 13, HFO, 5MW$_{-AC}$ PV	5		X	
Case 14, HFO, 10MW$_{-AC}$ PV	10		X	
Case 15, LNG, 5MW$_{-AC}$ PV	5			X
Case 16, LNG, 10MW$_{-AC}$ PV	10			X

Sensitivity Cases 17 - 28

In order to account for the inherent uncertainty associated with the key assumptions of fuel price, load levels and distributed PV uptake, multiple forecasts for each variable were developed and described in Appendix A. The various forecasts were grouped into possible futures under which each least-cost portfolio case was further evaluated. The least-cost portfolio cases are defined as the least-cost of each fuel type from the subset of portfolio cases (6 – 11) and the corresponding BAU cases (8 and 9). The possible futures are defined as follows:

- **High Fuel**: This future assumes that fuel prices follow the high price path that is based on the AEO 2015 "High Oil" forecast. As a result of the high fuel prices customers have additional financial incentive to move to distributed generation and PV uptake doubles from the base forecast. Demand remains at base case levels, although higher distributed PV uptake effectively reduces demand for CUC generation.
- **High Demand**: Demand growth is driven by strong macro-economic factors, not by low fuel prices. CUC fuel costs remain at base case forecast levels. Distributed PV uptake remains at base levels, with demand growth met with additional CUC resources.
- **Low Fuel**: In a best case scenario, demand growth is driven by strong macro-economic factors and by low fuel prices. Low fuel costs provide little incentive for customers to increase PV uptake, which remains at base case levels. As in the High Demand case, demand growth is met with additional CUC resources.

Sensitivity Cases 17 through 28 are summarized in Table 4-3 below:

Table 4-3
"Sensitivity" Cases

Case	Potential Future	Assumptions Based on:	Demand Forecast	Fuel Price Forecast
Case 17, BAU, 10MW PV	High Fuel	Case 9	Base	High
Case 18, BAU, 10MW PV	High Demand	Case 9	High	Base
Case 19, BAU, 10MW PV	Low Fuel	Case 9	High	Low
Case 20, LFO, 10MW PV	High Fuel	Case 12	Base	High
Case 21, LFO, 10MW PV	High Demand	Case 12	High	Base
Case 22, LFO, 10MW PV	Low Fuel	Case 12	High	Low
Case 23, HFO, 10MW PV	High Fuel	Case 14	Base	High
Case 24, HFO, 10MW PV	High Demand	Case 14	High	Base
Case 25, HFO, 10MW PV	Low Fuel	Case 14	High	Low
Case 26, LNG, 10MW PV	High Fuel	Case 16	Base	High
Case 27, LNG, 10MW PV	High Demand	Case 16	High	Base
Case 28, LNG, 10MW PV	Low Fuel	Case 16	High	Low

Section 5
PRODUCTION COST MODELING RESULTS

The scenarios and sensitivities described in the previous Section were evaluated using ABB's PROMOD IV® (PROMOD®). For the IRP, Leidos developed a PROMOD® database based on the assumptions detailed in Appendix A of this report and modeled each island (Saipan, Tinian, and Rota) separately and then aggregated those results for reporting purposes.

PROMOD® Model Overview

The PROMOD® production cost model provides representation of generating resources and their potential dispatch using an hourly chronological dispatch algorithm to meet system energy requirements. PROMOD® incorporates characterizations of generator operating constraints such as ramp rates and minimum operating and shutdown time constraints to provide a realistic forecast of unit operations. In addition, system level constraints such as operating reserve requirements can be modeled to more accurately reflect the expected dispatch of generating units.

PROMOD® determines the least-cost dispatch active generating units in its database in each hour of the study period while honoring constraints included in the simulations. PROMOD® does not add or retire units to optimize costs.

Expansion Plan Methodology

Expansion plans were driven by the scenario development process, which was in turn driven by the pool of candidate resources from the RFP process. Each scenario was evaluated in order to produce a transparent set of quantified results that could be considered by CUC and stakeholders along with qualitative issues of importance to each group.

Several criteria were used to create expansion plans to model in PROMOD®:

- Candidate resources were added to each case on the commercial operations date supplied by bidders at the site specified by the bidder (if applicable).
- Existing resource retirements coincided with the new resource additions.
- A minimum quantity of existing resources at Power Plant 1 and Power Plant 2 on Saipan, depending on the case, were kept operational for backup purposes to maintain reliability.
- In an iterative process, candidate resources were added in sufficient quantities to maintain reliability at levels similar to the BAU case.

Base Case Results

The "Base" cases are intended to quantify the production cost of generation using three fuels - LFO, HFO, and LNG – compared to the BAU case. Expansion and retirement plans were dictated by the bids received for each resource, which specified the location of the new power plant (either the Power Plant 1 or Power Plant 4 site) and the expected commercial operations date. The LNG options assumed a commercial operations date of January 1, 2020 in order to give enough lead time to install the necessary LNG regasification infrastructure.

Tables 5-1 through 5-4 provide summaries of the projected additions and retirements associated with each of the Base Case variations. It is important to note that in each case, more than four units were required on Saipan to maintain reliability, measured by loss-of-load-hours in PROMOD®, at levels consistent with the BAU case. While each bidder proposed four units for Saipan, it was assumed that proposals could be scaled to meet the requirements of CUC at the same unit cost as the proposal. Several bidders explicitly stated that their proposal was scalable but the cost would need to be revisited in the final procurement process.

Appendix C of this report contains detailed, annual operations and cost projections for each of the Base Case variations.

Table 5-1
Case 2 (LFO) Planned Additions and Retirements

	Island	Unit	2016	2017	2018	2019	2020
Additions (MW)	Saipan	5 Recip. Units @ 8.47MW	42.4				
	Saipan						
	Rota						
	Tinian						
	Total		**42.4**	**0.0**	**0.0**	**0.0**	**0.0**
Retirements (MW)	Saipan	PP4 All Units	13.0				
	Saipan	PP1 Units 1, 2, 3, 6, 7	36.5				
	Rota						
	Tinian						
	Total		**49.5**	**0.0**	**0.0**	**0.0**	**0.0**

Table 5-2
Case 3 (HFO) Planned Additions and Retirements

	Island	Unit	2016	2017	2018	2019	2020
Additions (MW)	Saipan	6 Recip. Units @ 8.15MW			48.9		
	Saipan						
	Rota						
	Tinian						
	Total		**0.0**	**0.0**	**48.9**	**0.0**	**0.0**
Retirements (MW)	Saipan	PP1 All Units			60.0		
	Saipan						
	Rota						
	Tinian						
	Total		**0.0**	**0.0**	**60.0**	**0.0**	**0.0**

Table 5-3
Case 4 (LNG Saipan) Planned Additions and Retirements

	Island	Unit	2016	2017	2018	2019	2020
Additions (MW)	Saipan	6 Recip. Units @ 7.35MW					44.1
	Saipan						
	Rota						
	Tinian						
	Total		**0.0**	**0.0**	**0.0**	**0.0**	**44.1**
Retirements (MW)	Saipan	PP1 All Units					60.0
	Saipan						
	Rota						
	Tinian						
	Total		**0.0**	**0.0**	**0.0**	**0.0**	**60.0**

Table 5-4
Case 5 (LNG All) Planned Additions and Retirements

	Island	Unit	2016	2017	2018	2019	2020
Additions (MW)	Saipan	6 Recip. Units @ 7.35MW					44.1
	Saipan						
	Rota	3 Recip. Units @ 2.15MW					6.5
	Tinian	5 Recip. Units @ 2.15MW					10.8
	Total		**0.0**	**0.0**	**0.0**	**0.0**	**61.3**
Retirements (MW)	Saipan	PP1 All Units					60.0
	Saipan						
	Rota	All Units					7.5
	Tinian	All Units					18.2
	Total		**0.0**	**0.0**	**0.0**	**0.0**	**85.7**

Table 5-5 provides a levelized cost comparison of the bases cases and the BAU case. The LFO and HFO cases are similar in cost to the BAU case. Both Case 2 and the BAU case burn LFO, but the additional cost of the new units in Case 2 pushes the levelized cost above the BAU case. All base cases resulted in a more reliable system than the BAU case (as measured by LOLP), which must be measured against the costs quantified in the IRP.

Table 5-5
Base Case Levelized Production Cost Comparison ($/MWh)

Case	Levelized Cost ($/MWh)	Diff. From Case 1 ($/MWh)	% Difference from Reference Case (Case 1)
Case 1 - BAU	464.48		
Case 2 - LFO	480.40	15.93	3.4%
Case 3 - HFO	460.42	(4.05)	-0.9%
Case 4 - LNG Saipan	353.42	(111.05)	-23.9%
Case 5 - LNG All	334.23	(130.24)	-28.0%

The LNG cases are substantially lower cost than the fuel oil cases as clearly shown in Table 5-5 above and Figure 5.1 below, but are based on planning level estimates for LNG infrastructure, shipping costs, and new generation unit capital costs. Further investigation of the LNG options are warranted given the substantial potential cost savings. The all-island LNG Case 5 assumes LNG is available to replace the existing units on Tinian in 2020. This may not be possible due to the terms of the CUC contract with Telesource. However, the 2020 start date was used to illustrate the high-level cost savings potential. Should the LNG option be pursued, the terms of the Telesource contract would dictate the earliest commercial operations date for new LNG on Tinian unless the Telesource agreement were to be renegotiated, the determination of which falls outside the scope of this IRP.

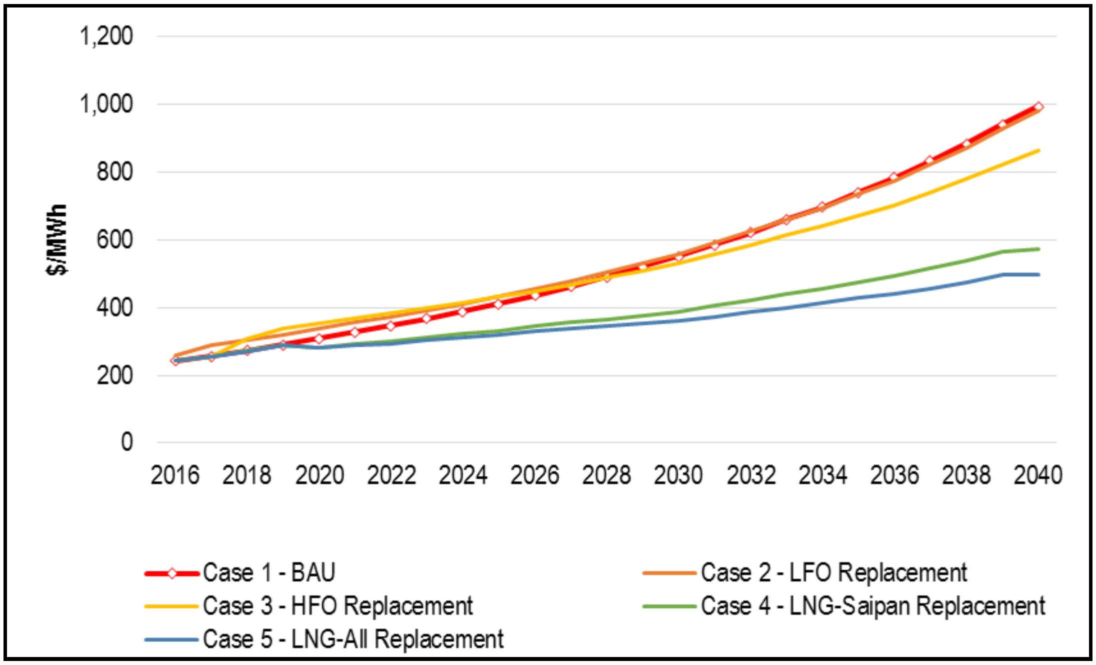


Figure 5.1: Base Case Annual Levelized Production Costs ($/MWh)

Cases 6 – 10 Results (PV Additions)

Costs for each PV proposal were evaluated individually in PROMOD® by adding each alternative to the BAU case. Solar bids ranged from 1 to 10 MW_{AC} in size and were modeled in PROMOD® using the hourly load profile provided by each bidder. CUC's renewable integration study provided guidance on requirements for integrating renewable energy on the CUC system including the maximum quantity feasible without significant system upgrades and the quantity that can be installed without the need for ramp rate control to mitigate sudden changes in renewable generation output. All cases analyzed in the IRP were well below the 24 MW_{AC} of installed renewable capacity quoted in the report that would require system modifications. The renewable integrations study analyzed a dispersed renewable scenario with up to 4 MW_{AC} of renewables per feeder. The IRP assumed PV installations above that 4 MW_{AC} value would require storage for ramp rate control. Costs for storage, provided by the bidders, were added to Cases 8, 9, and 10, accordingly.

Table 5-6 and Figure 5.2 show the relative cost of each solar PV case as compared to the BAU case.

The 10 MW-$_{AC}$ Renewable 2 alternative was evaluated with and without the ITC and accelerated depreciation that are set to be reduced at the end of 2016. The elimination of the tax benefits would increase the cost of Case 10 above the 10 MW-$_{AC}$ Renewable 1 alternative, which has a planned commercial operations date in 2018 (already beyond the ITC reduction). PV reduces costs in each case, suggesting that solar PV should have a place in CUC's future generation resource mix.

Table 5-6
PV Cases Levelized Production Cost Comparison ($/MWh)

Case	Levelized Cost ($/MWh)	Diff. From Case 1 ($/MWh)	% Difference from Reference Case (Case 1)
Case 1 - BAU	464.48		
Case 6 - BAU, 1MW-$_{AC}$ PV1	451.65	(12.82)	-2.8%
Case 7 - BAU, 2MW-$_{AC}$ PV1	450.19	(14.29)	-3.1%
Case 8 - BAU, 5MW-$_{AC}$ PV1	446.36	(18.12)	-3.9%
Case 9 - BAU, 10MW-$_{AC}$ PV1	439.26	(25.22)	-5.4%
Case 10 - BAU, 10MW-$_{AC}$ PV2	435.89	(28.58)	-6.2%
Case 10a - BAU, 10MW-$_{AC}$ PV2 No ITC	443.03	(21.45)	-4.6%

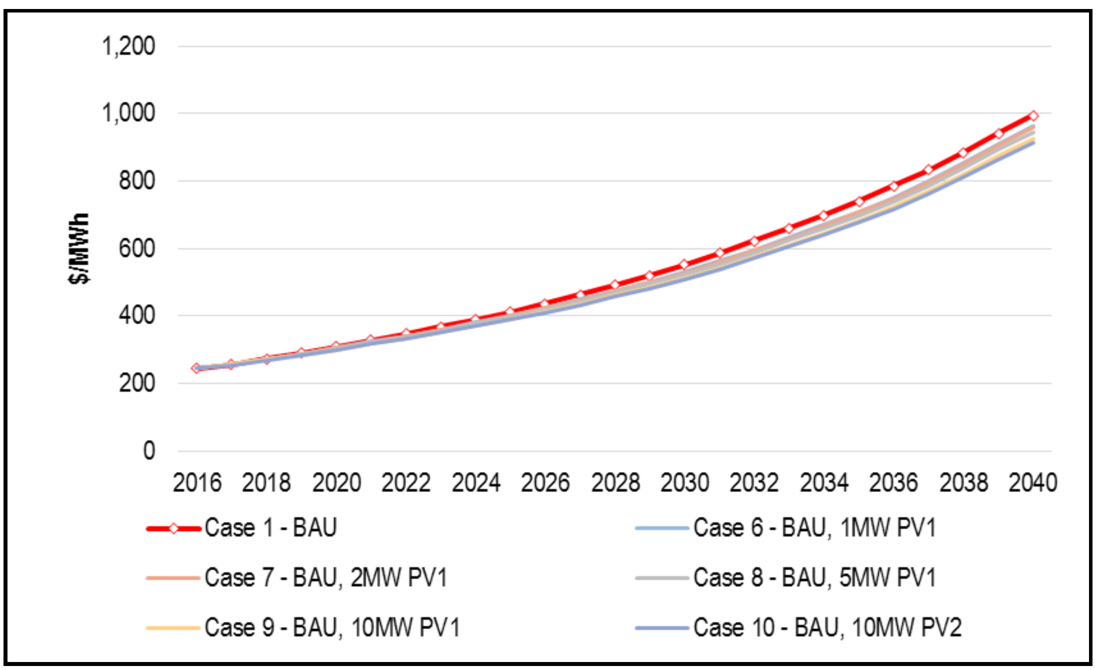


Figure 5.2: PV Cases Annual Levelized Production Costs ($/MWh)

Carbon Intensity

In addition to production costs, the IRP also evaluated the effect of the various generation alternatives on carbon intensity (pound of carbon dioxide (CO_2) emitted per MWh of electricity sales, including effects of losses). Figure 5.3 shows the average carbon intensity for each of the first 10 cases analyzed in the IRP. Results are as expected:

- Case 2 intensity is below the BAU case due to more efficient generating units
- Emission rates for HFO are higher than the LFO cases
- LNG cases have the lowest emission rates
- Adding PV reduces carbon intensity

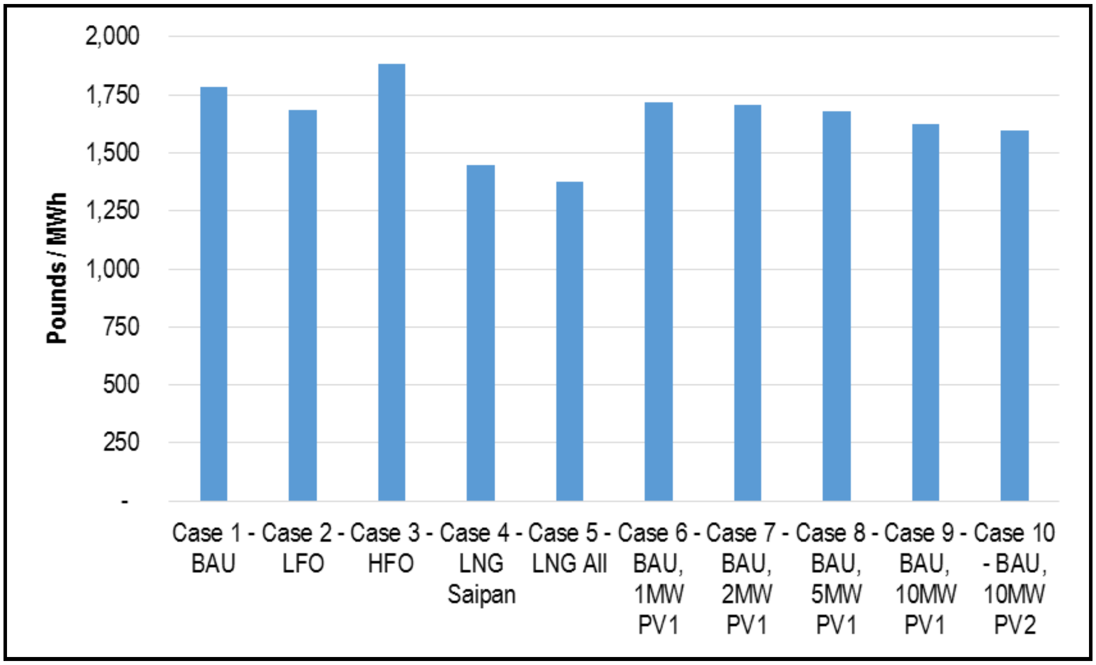


Figure 5.3: Carbon Intensity for Cases 1-10

Portfolio Case Results

Given the lower cost of solar PV compared with the other dispatchable generation options, "Portfolio" cases were evaluated to determine cost savings from a plausible combination of new renewable generation and new thermal generation. "Portfolio" cases were evaluated that added solar PV to each of four base cases: 1) BAU, 2) LFO, 3) HFO, and 4) LNG All-Islands. Based on the PV results from the previous section and discussions with CUC about the likelihood of a project being completed by the end of 2016, the Renewable 1 alternative was selected as the lowest cost PV resource for the portfolio cases.

Table 5-7 shows that additional PV reduces production costs compared to the base case of each fuel scenario, including the lowest cost LNG case.

Table 5-7
Portfolio Cases Levelized Production Cost Comparison ($/MWh)

Portfolio	BAU (Case 1)	LFO (Case 2)	HFO (Case 3)	LNG All (Case 5)
Base Case	464.48	480.40	460.42	334.23
+5MW$_{\text{-AC}}$ PV	446.36	473.66	456.80	331.06
+10MW$_{\text{-AC}}$ PV	439.26	466.88	453.09	329.02
Savings from Base				
+5MW$_{\text{-AC}}$ PV	(18.12)	(6.74)	(3.62)	(3.18)
+10MW$_{\text{-AC}}$ PV	(7.10)	(6.78)	(3.71)	(2.04)

Sensitivity Results

Sensitivity cases, as described in the Scenario Development section of the IRP report, were analyzed to highlight the impact of changing key assumptions that are inherently more uncertain than others such as the load and fuel price forecasts. As shown in Table 5-8, costs in the "High Fuel" sensitivity are well above the BAU case with the notable exception of the LNG sensitivity which, despite higher LNG prices, is still lower cost than the BAU case.

Table 5-8
Sensitivity Cases Levelized Production Cost Comparison ($/MWh)
(Percent Change from BAU Case)

Portfolio	BAU (Case 1)	LFO (Case 2)	HFO (Case 3)	LNG All (Case 5)
Base Case	NA	3.4%	-0.9%	-28.0%
+10MW PV, "High Fuel"	60.0%	62.3%	48.3%	-17.6%
+10MW PV, "High Demand"	-1.7%	3.8%	-1.0%	-32.3%
+10MW PV, "Low Fuel"	-30.0%	-23.0%	-23.3%	-36.4%

Sensitivities with the high demand forecast, "High Demand" and "Low Fuel" required modifications to the expansion plans to account for the increased load. Generation assets in the BAU cases were fixed but each of the three other cases required two additional generation units on Saipan and five additional units on Tinian in the LNG case. Based on the scenarios evaluated, no options were available to increase generation capacity on Rota and Tinian in the LFO and HFO cases. Because demand increased and generation capacity was fixed, reliability decreased as measured by an increase of loss-of-load-hours reported in PROMOD®. This has the effect of slightly under estimating production costs for the purpose of the IRP but highlights the need for additional generating capacity should large discrete load increases become likely on Tinian.

Results Summary and Findings

The IRP evaluated 16 cases representing combinations of candidate generating resource burning three different fuels plus solar PV, all under the assumption that CUC would endorse the DSM portfolio. Table 5-9 ranks each case from least-cost to highest cost. The table indicates that of all 16 cases, the least cost scenario is Case 16, with a levelized cost of $329.02/MWh. This scenario would include replacing all generation on all three islands with LNG-fueled engines, as well as including 10MW-$_{AC}$ of PV.

After the LNG cases, the next least cost scenarios involve the BAU cases, with and without the addition of (lower cost) PV. The HFO base case (Case 3) is projected to be slightly less costly than the BAU base case (Case 1); however, the projected cost difference of approximately one percent cannot be considered significant in an IRP. Indeed, all of the BAU, HFO, and LFO cases can be considered to be very comparable in costs, with projected differences being not material in a planning study.

Table 5-9
Cases 1 – 16 Ranked Levelized Production Cost Comparison ($/MWh)

Case	Levelized Cost ($/MWh)	Diff. From Case 1 ($/MWh)	% Difference from Reference Case (Case 1)
Case 16 - LNG All, 10MW-$_{AC}$ PV	329.02	(135.46)	-29%
Case 15 - LNG All, 5MW-$_{AC}$ PV	331.06	(133.42)	-29%
Case 5 - LNG All	334.23	(130.24)	-28%
Case 4 - LNG Saipan	353.42	(111.05)	-24%
Case 10 - BAU, 10MW-$_{AC}$ PV2	435.89	(28.58)	-6%
Case 9 - BAU, 10MW-$_{AC}$ PV1	439.26	(25.22)	-5%
Case 8 - BAU, 5MW-$_{AC}$ PV1	446.36	(18.12)	-4%
Case 7 - BAU, 2MW-$_{AC}$ PV1	450.19	(14.29)	-3%
Case 6 - BAU, 1MW-$_{AC}$ PV1	451.65	(12.82)	-3%
Case 14 - HFO, 10MW-$_{AC}$ PV	453.09	(11.38)	-2%
Case 13 - HFO, 5MW-$_{AC}$ PV	456.80	(7.67)	-2%
Case 3 – HFO	460.42	(4.05)	-1%
Case 1 – BAU	**464.48**	**0**	**0%**
Case 12 - LFO, 10MW-$_{AC}$ PV	466.88	2.40	1%
Case 11 - LFO, 5MW-$_{AC}$ PV	473.66	9.18	2%
Case 2 – LFO	480.40	15.93	3%

Section 6
FINDINGS AND RECOMMENDED ACTIONS

In the preparation of the IRP, we have made certain assumptions with respect to conditions that may occur in the future. While we believe these assumptions are reasonable for the purpose of this analysis, they are dependent upon future events and actual conditions may differ from those assumed. In addition, we have used and relied upon certain information and assumptions provided to us by others including CUC. While we believe the sources to be reliable, we have not independently verified the information and offer no assurances with respect thereto. To the extent that actual future conditions differ from those assumed herein or provided to us by others, the actual results will vary from those forecast. The principal considerations and assumptions made by us in preparing the IRP over the study period beginning on January 1, 2016 are summarized below.

The assumptions, evaluations, and analyses conducted for purposes of the CUC IRP support several key findings when reviewing the production cost results in Section 5:

1. Energy efficiency measures such as residential lighting and water measures, and commercial lighting and refrigeration measures are projected to be materially less costly than any of the supply side options, including oil and LNG fueled generation alternatives, as well as PV generation alternatives.
2. PV generating facilities are projected to be materially less costly than any of the oil and LNG fueled alternatives. However, their relative savings is significantly lower than the LNG alternative as a result of the bounded capacity value of PV during the utility's peak demand periods and the relatively low AC capacity factor that can be expected from a new PV installation.
3. The LNG fueled alternative is projected to be materially less costly than any of the oil fueled generation alternatives.
4. All of the oil fueled generation alternatives, including the BAU, LFO, and HFO options, are not projected to have materially different costs relative to each other.

The four primary findings are described below, followed by a number of recommendations related to CUC's operations and future planning efforts.

Oil Fueled Generation

The Energy Supply RFP received a number of bids related to oil fueled generation options, indicating a robust market available to CUC for these resources. The decision to pursue new oil fueled generation options must carefully consider all of the implications identified in the IRP, including:

Reliability issues associated with the BAU option

The BAU option contemplates continued operation of CUC's existing oil fueled assets by effectively extending their useful lives indefinitely. While this likely is a technically feasible option, it must be noted that the scarcity of adequate replacement parts for Power Plants 1 and 4 may eventually force the retirement of those assets. In addition, as the assets age, forced outages are likely to increase, even with diligent efforts by plant engineers to prevent them. Further, the costs associated with indefinitely extending the lives of the assets may potentially exceed the estimates used in the IRP.

Fuel oil price volatility

Even though oil prices have dropped from $107 per barrel to less than $50 per barrel over the last several months, it remains an expensive fuel relative to other feasible options for CUC such as renewable generation and natural gas. Further, in addition to CUC being exposed to broad pricing trends in the world oil markets, near term fluctuations in oil market pricing can cause CUC's delivered fuel prices to vary significantly on a monthly basis. This volatility can cause associated swings in the LEAC adjustments for customer bills, which can in turn cause hardship for many of CUC's customers, who already are paying relatively high rates for their power.

Environmental impacts of HFO vs. LFO

As described in Section 3, the HFO option identified through a bid to the Energy Supply RFP and evaluated in the IRP process contains a significant amount of regulatory and economic uncertainty. Leidos and CUC extensively discussed this issue during the IRP development, and ultimately decided to make a reasonable effort to identify the potential costs associated with permitting and siting a new HFO facility. However, in doing so, both Leidos and CUC acknowledge that only through a detailed HFO feasibility and regulatory compliance study can more accurate projections be made relative to those potential costs.

Further, given the CNMI and CUC's desire to pursue sustainable energy development, the environmental impacts of using HFO to generate electricity cannot be ignored, regardless of the economics. Additionally, substantial new fuel handling infrastructure would be required to accommodate the toxic nature of HFO; the new infrastructure would impose additional environmental impacts as well as additional costs. CUC and the CNMI must carefully consider environmental and sustainability goals when evaluating whether to pursue an HFO solution.

Similar costs across fuel oil options

As noted above, Leidos projects that the three oil fueled scenarios – the BAU, the LFO, and the HFO options –do not have materially different cost structures.. Differences of 1-5 percent in levelized energy costs are insignificant from a planning perspective and given the inherent uncertainty in many of the IRP assumptions. CUC has the flexibility to choose any of these three options to pursue from an economic standpoint. Because of this, non-economic factors such as fuel price volatility, regulatory and environmental impacts, and system reliability may take on greater significance during the decision process.

Liquefied Natural Gas-Fired Generation

The IRP process and analytical results have identified that the four LNG cases evaluated were less costly than all oil fueled cases by a wide margin. While the LNG cost estimates developed by Leidos do not represent firm bids, the significant cost differential between the fuel oil options and LNG appears large enough to warrant a detailed feasibility study of LNG as a fuel for electric generation for CUC.

Such a feasibility study may include evaluation of potential regional partnerships regarding the development of LNG facilities, such as partnering with the GPA or other Micronesian partners to jointly develop a central LNG regasification facility and shipping facilities.

In Leidos' experience, evaluating the feasibility of LNG facilities followed by the actual development of such facilities occurs on an extended timeframe, often taking multiple years. As such, Leidos believes that if CUC wishes to pursue an LNG solution, it would be prudent to begin that effort in earnest as soon as practicable.

PV Generation Development

Assuming the pricing structures bid into the Energy Supply RFP, utility scale PV facilities will be materially less costly than oil- and LNG-fired generation options.

Also as with LNG, there remain a number of uncertainties related to the PV bids received in response to the RFP. Suitable land areas and land acquisition are expected to be significant challenges with respect to the development of utility-scale PV generation. Additionally, the Renewable Integration Study identified an upper limit to how much intermittent, renewable generation could be accommodated given CUC's existing assets and system infrastructure. The study found that the CUC system could accommodate up to approximately 26 MW_{-AC} of geographically dispersed, intermittent generation, provided the facilities incorporate energy storage for ramp-rate control, as the selected 10 MW_{-AC} PV option does. It is possible that that limit may be exceeded given certain infrastructure upgrades, but those potential upgrades have not yet been contemplated by CUC.

The IRP has identified a qualified bid by a qualified vendor, which was the most economical of all PV bids provided in response to the RFP. Should CUC wish to pursue this cost effective resource, it would be prudent to begin that pursuit as soon as practicable with the bidder identified.

Demand-Side Management Options

As with the PV and LNG options, the IRP has indicated that the DSM measures and programs modeled by Leidos would reduce costs to CUC customers in all cases. The magnitude of savings would be determined by the specific energy use for a given customer, as well as the types of measures that customer may deploy. DSM solutions are likely to be mutually beneficial for CUC and its customers, with the up-front costs and resulting benefits shared between the utility and electricity consumers. DSM options would likely be seen as a valuable service by CUC, and ultimately would help lower customer bills, which was a key stakeholder priority identified during the development of the IRP.

Recommended Actions

The careful consideration of the entire IRP document, its associated appendices, and its findings is critical prior to CUC making any decisions related to future assets. The decisions that CUC makes relative to the four primary findings of the IRP may well impact the CNMI for decades to come.

Leidos has identified the following recommendations related to CUC's operations and future planning efforts:

Develop IRP Implementation Plan

As discussed during the Leidos and CUC conference calls, and video presentations, it is critical that CUC establish an implementation plan for the IRP as soon as possible, including specific milestones. Having such a process in place prior to releasing the IRP to the public will be critical to the ultimate success of the IRP. Typical implementation plans may include the following activities:

> ***Procurement Decision.*** CUC should carefully consider this entire IRP and its implications prior to reaching any decision related to potential procurement of one of the Energy Supply RFP bids described in this IRP. Further, given the amount of stakeholder interest in the IRP and CUC's future, such a decision should be made within the context of a transparent and open process, which will carefully consider the economic and environmental impacts associated with any resource decision. While CUC may choose to pursue the BAU case and not pursue any new resource procurement at this time, such a choice would likely continue to erode customer confidence in CUC, keep electricity rates high, and subject Saipan to increasingly unreliable electric service.
>
> ***Procurement Implementation.*** Upon reaching a procurement decision, CUC will likely need to execute a number of detailed implementation studies. These studies will identify the technical considerations required to develop new generating and demand-side resources, and integrate them onto CUC's system. Implementation studies may include interconnection studies, fuel infrastructure requirement studies, environmental permitting and siting studies, and more.
>
> ***Procurement Negotiations.*** Should CUC decide to pursue new resource options, it will likely need to negotiate either an EPC contract, a PPA, or both. Negotiations will necessarily include the economic, financial, technical, and environmental considerations, which must be incorporated into the terms and conditions of such agreements.

> ***Resource Development.*** Upon successful negotiation of a development agreement, CUC will need to commence the development of resources it has chosen to pursue. While it may be possible that any development will be completed by a third party, CUC must be prepared to spend considerable time and effort to manage such a process. Additional advisory services such as owners' engineering services may be necessary for CUC to pursue, given limited staff time and experience in generation development.

IRP Maintenance. This IRP is a comprehensive analysis of CUC's future resource needs and options for meeting those needs. To remain a viable plan, the IRP should be revisited at regular intervals by CUC management and make revisions as necessary to ensure its continued relevancy. The dynamic nature of the electric industry today indicates that IRPs should be nearly continuously monitored and reviewed in order to maintain their effectiveness.

Collect and Warehouse Operations Data

CUC-supplied data related to hourly loads, generation, distributed PV penetration, sales, fuel costs, and other key system parameters was in short supply. Leidos recognizes the efforts of the CUC IRP team to provide this data and acknowledges that in many cases, the data simply did not exist. To aid future planning efforts and operational budgeting and benchmarking, Leidos recommends that CUC initiate a data collection and retention program to ensure the future availability of this critical data, which can be used across the utility.

Develop a Fuel Price Hedging Program

Given that CUC is certainly going to be purchasing fuel oil for the near term, and likely beyond that, and also given the inherent volatility in fuel prices, CUC would benefit by investigating the possibility of establishing a fuel price hedging program. Such a program could be used to mitigate the price swings, which are inevitable in the world oil markets, and which ultimately impact CUC's customers.

Conduct a Cost-of-Service Study

There is substantial interest across the stakeholder spectrum in reducing CUC's operating costs and, thus, lowering customer rates. The IRP has identified options for reducing CUC's generation-related costs. Further efforts to reduce rates would be benefitted by CUC conducting a Cost-of-Service study, to identify the true costs of service by customer class and quantify administrative and general expenses. The results of such a study would be highly useful in determining whether rate design modifications may be appropriate to more accurately recover CUC's true costs of service.

Introduction

The purpose of this Assumptions Document is threefold. First and most importantly, this document serves as a comprehensive warehouse for all of the key inputs and approaches to analysis that will either immediately precede or underpin the CUC Integrated Resource Plan (IRP). This tracking of all inputs into the IRP provides a transparent platform to foster consensus internal to CUC and ensure a successful result that is predicated on well-documented intermediary elements of the ultimate result. Secondly, this Assumptions Document serves as the springboard for both the final CUC IRP report, as well as the CUC IRP Strategy Document, the latter of which will reflect the strategy to be deployed across the entire IRP execution process that is predicated upon the assumptions delineated herein. Finally, the document serves as the evolving workspace within which certain critical components of the approach to the IRP that are highly dependent upon the results of the ongoing procurement/RFP process will need to be iterated upon prior to the beginning of detailed dispatch modeling. By working to codify such RFP-dependent components of the analysis, costly re-work due to lack of clarity regarding what can practically be modeled given the tractability and extent of available data can be avoided.

Each subsection of this document will articulate the specific assumption(s) that Leidos intends to use, the source/basis for such assumption, and a description of certain methodological details in support of a given assumption, as appropriate. As noted above, the domain of future resource options available to CUC is highly dependent upon the nature and extent of bids received. Additionally, the definition of production cost scenarios and scenarios associated with the drivers of production cost (e.g. fuel costs), while defined preliminarily below, will need to remain flexible and amenable to various combinations of resources made available to CUC through the procurement bids and/or made available as generic resources modeled by Leidos, as applicable and as defined below. Consequently, certain subsections below have been marked "[to come]", and will be populated in consultation with CUC as the IRP moves forward[4]. Additional areas of focus for the Assumptions Document, which will evolve as more data becomes available, include parameterization of CUC's existing asset base by island, and other key inputs to both the screening analysis and the downstream production cost modeling using the PROMOD platform.

It should be noted that key numerical outputs that reflect projections or key resource assumptions have been included as a series of appendices to this document, wherever appropriate. Refer to each subsection below for a cataloguing of each key appendix.

[4] While the draft of this Assumptions Document may be "complete" for purposes of this iteration of the CUC IRP, the bracketing approach can be preserved (and has been preserved) in order to facilitate future IRP iterations.

Upon finalization, each appendix will contain all of the core numerical inputs into the screening analysis and the production cost modeling.

Study Period

Based on discussions with CUC, the IRP will have a 25 year study period over 2016 – 2040. Projections of CUC load, fuel prices, and other key cost estimates required to perform the screening and production cost modeling will be prepared over this same duration.

Financial Inputs and Escalation Factors

Based on discussions and input from CUC, the following assumptions will be used for general inflation and CUC's cost of capital:

- CUC does not have an island-specific view regarding inflationary expectations. While data on consumer price index (CPI) metrics has been collected by Leidos from the Department of Commerce (DOC), this data does not include a projection of inflation. CUC has directed Leidos to utilize an inflation assumption consistent with that used for similar project work conducted for Guam Power Authority (GPA). Consequently, Leidos will use an inflation assumption of 3.3% per year, consistent with our most recent resource planning and screening engagements with GPA. This rate is based on Moody's projection of the CPI-based inflation rate on Guam over the period 2014-2035 as based on the most recent vintage of economic data available in support of the Guam load forecast.
- With regard to CUC's cost of capital, a similar approach will be taken, wherein we will use a cost of capital of 5% per year, consistent with our most recent bond related assignments for Guam.

CUC Load Forecast and Hourly Load Shapes

The CUC Load Forecast has been prepared using a combination of (i) detailed econometric analysis to project "organic" retail sales across each of the three independent islands, (ii) a separate discrete load additions model that tracks all anticipated hotel and casino load additions (either due to new construction or as a result of anticipated returns to grid service by customers who qualify for CUC's incentive rate), assigns them to one of the islands, and estimates the incremental impact on energy and peak demand, and (iii) a parameterization and subsequent projection of potential roof-top solar installations that have the potential to reduce future load to be served by the grid. Each of these methods is described herein, followed by a description of how the base case forecast has been constructed from the various model outcomes.

Detailed econometric analysis to project "organic" retail sales was conducted using monthly retail sales data provided by CUC's rate consultant over the period October 2005 - April 2014 for each island. Retail classes modeled include the residential, commercial, and governmental classes. Given the disproportionate influence of Saipan on the total system, as well as the fact that each island is an independent system, detailed econometric analysis was performed for the Saipan retail classes, with the other two islands' sales projected based on relational models that are dependent upon the Saipan forecast. Saipan residential sales have been projected on the basis of an econometric model of average usage coupled with a projection of anticipated changes in the residential customer base on Saipan. Commercial and governmental sales have been projected based on unique econometric models that relate historical changes in kWh sales to CNMI real Gross Domestic Product (GDP) and hotel occupancy, respectively. Numerous other potential explanatory variables, including heating and cooling degree days extracted for a weather station representative of the CUC system, numerous CPI indices, indicators that track minimum wage levels, and native statistics on arrivals, were investigated for their efficacy in explaining historical variation in Saipan load levels. The models that performed best in explaining historical variation were retained for forecasting purposes, with each explanatory variable simulated into the future to result in sales projections for Saipan, which were then inserted into the Tinian and Rota models to complete the retail sales projections.

In general, the key explanatory variables within the modeling, which as noted above has been done on a retail class basis, are real GDP of the CNMI, population, real average revenue by class, seasonal terms, and certain other econometric adjustments required to address intermittent anomalies within the data. A population projection from Moody's has been provided to Leidos based on our existing relationship with that vendor. We have also utilized our standard approach to project real average revenues, which we have assumed will be constant in real terms (or increase commensurate with general inflation). Additionally, hotel occupancy levels for properties that currently operate within the CUC system were assumed to perpetuate into the future based on a 5 year average of available occupancy levels.

A unique component of the econometric analysis for CUC is the fact that, absent a singular population projection as compiled by Moody's, there are no externally derived projections of independent variables that would typically be leveraged to simulate the econometric models into the future. Consequently, Leidos has engaged in a significant research effort in order to derive a correlate for CNMI GDP that can be used to produce a reasonable projection of that variable and, consequently, the retail sales models that are best explained by this variable. As tourism is the central driver of the CNMI economy, the focus of this investigation was on metrics related to tourism that could be correlated to the downturn in CNMI real GDP.

The recent challenges within the CNMI and specifically CUC load loss during the recent recession is no secret. A June 2011 study by the U.S. General Accountability Office found that:

- Employment in all sectors in the CNMI decreased by 13% from 2008-2009, while employment in tourism decreased by 8%.
- Earnings of all employed during 2008-2009 increased by 3% above and beyond the inflation rate for that year, while earnings by minimum-wage earners who kept their employment and work hours in 2008-2009 increased by 9%.

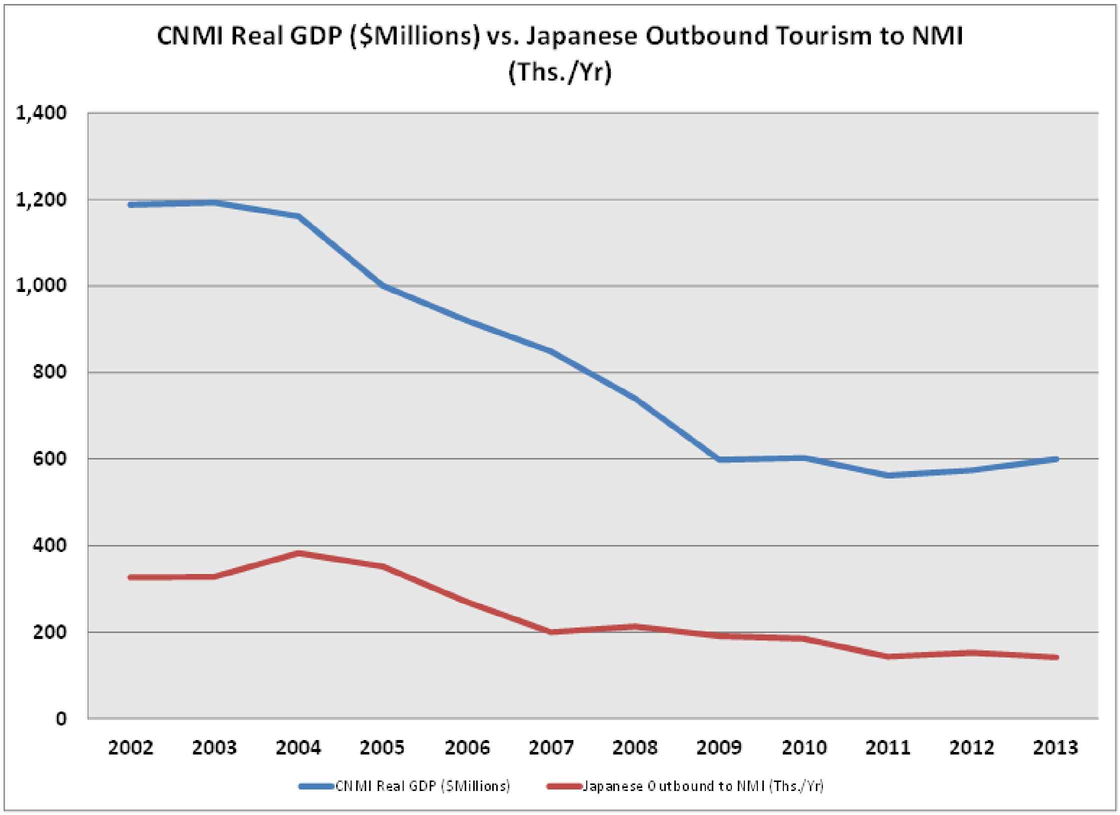
- 73% of those working in tourism had an increase in wages following the September 2010 minimum wage increase.
- By early 2012, tourism employers representing 62% of workers have plans to lay off workers, although none indicated the action to be a result of minimum wage increases.
- CNMI workers surveyed indicated that they would like raises but worry about losing their jobs or a reduction in their work hours.

With such decidedly mixed economic indicators, it was critical to obtain a reasonable short to medium term view on the potential for resurgence (if any) with respect to GDP, which is materially driven from tourism, as has been noted in a recent First Hawaiian Bank profile on Guam and the CNMI.

In order to obtain a view regarding CNMI GDP recovery potential, Leidos investigated the World Bank data associated with tourism to the Northern Mariana islands from the three most frequently cited countries. Based on this analysis, we were able to isolate the relationship between Japanese outbound tourism and recent declines in CNMI real GDP. Such a model performs remarkably well in explaining CNMI GDP variations. Consequently, we have researched and extracted a short to medium term view regarding outbound tourism from Japan from a reputable source (Euromonitor.com), and have leveraged that information to project Northern Mariana tourism activity, and subsequently GDP. Given these projections, we can leverage the econometric models developed by retail class (as noted above) to complete our energy projections.

Leidos researched available data for Chinese as well as Korean outbound tourism and GDP metrics as made available by the World Bank. The advantage in using the Japanese data set is the fact that the Japanese data set compartmentalizes outbound tourists to Asia, North America, Micronesia, and other key locations, which allows us to drill down into estimated visitation statistics at a more granular level. Additionally, the Chinese and Korean economies appear to be much more insulated from the recent global recession (at least based on the World Bank's estimates of GDP in those nations), and consequently, the relationship between tourism activity in those nations in aggregate and real CNMI GDP is fairly weak.

The graphic below superimposes annual Japanese outbound tourism (in thousands per year) to the NMI as compared to CNMI Real GDP (in millions of dollars) as reported by the DOC.



As shown above, the relationship is fairly strong, which allows us to leverage the tourism variable econometrically in a GDP model.

Subsequent to the completion of the econometric analysis by island, it was necessary to estimate a loss percentage to capture the differential between retail sales and actual energy delivered for each island. CUC (and CUC's other consultants) report that no central repository for net energy for load (NEL) (or all energy generated inclusive of all losses) exists historically. Consequently, Leidos has conducted a historical loss percentage analysis based on multiple sources, namely (i) generation data for resources across each island, which were compared to monthly retail sales to develop an estimate of losses by month for the period of data overlap available, (ii) a subsequent review of total energy generated by island as tracked in a separate spreadsheet provided by CUC, and (iii) anecdotal evidence regarding the plausible range of losses that have been or may be experienced on each island. Each of these sources of data was compared against one another for benchmarking purposes, and was also ground-truthed relative to the implied load factors that would result from a given loss assumption as a function of available historical demand data for each island. The resulting loss factor assumed for load forecasting purposes was as follows:

CUC ISLAND LOSSES	
SAIPAN	16.37%
Tinian	15.61%
Rota	19.00%

The exact method used for arriving at the computed losses by island is:

- Using the island production data available, Net Energy for Load was computed as the difference between the "Generation Data" and the "Station Power" data.
- Using the NEL from above and the retail sales data available, losses were computed.
- Computed losses were averaged over a given period over which we have data, currently 3 years (2011-2013).

Demand by island was derived from total island level net energy for load (or energy inclusive of the loss factor applied as described above) based on the historical relationship between energy and load factor on a by-island basis. Historical demand for each island was extracted from a series of questionnaire spreadsheets associated with legacy power purchase agreement data provided by CUC. As each island is to be modeled as an independent system, the demand determinants of interest are the native peaks of each island. Consequently, there is no need to compute coincident peaks of a given island relative to any of the other islands.

Appendix A of this Assumptions Document summarizes historical and projected energy and peak demand by island over the IRP Study period, including specific additional assumptions regarding discrete load additions as described further below.

The resultant energy and demand projections by island as based on the approach above represent the "organic" load forecast, which does not account for (i) the impact of discrete load additions that may materialize on the CUC system as a consequence of new hotel or casino loads, or (ii) roof-top solar installations, which have been projected separately. Each of these issues has been addressed as described below.

To account for discrete loads, Leidos has developed a detailed discrete load characterization model that captures the estimated energy and peak demand impacts associated with all of the potential hotel/casino loads that may reconnect to the grid and/or be built. Based on detailed discussions with CUC's rate consultant, we have assigned each potential discrete load to one of the islands, and our model has the capability to add/subtract loads as well as adjust the timing of those loads. For the Base Case, the estimated impact associated with such loads has been based on "firm", or known load additions only. Given the rather large spread between known load additions and speculative load additions, we have also produced a "High Case" that reflects all incentive loads returning to grid service and all hotel loads active at 25% of their quoted energy and demand levels. The High Case reflects a conservative cap on nominal load levels that assumes a 1 in 4 likelihood for any given hotel load to actually materialize. The High Case reflects a demand increase of as much as 25 MW in aggregate by the end of the Study Period relative to projected "organic" load growth[5] as summarized in Appendix A. As we develop downstream scenarios of loads, we will adjust these assumptions to understand the impact of discrete load additions in partnership with CUC.

With regard to roof-top solar installations, Leidos has completed the parameterization of roof-top solar installations by island based on PVSyst hourly simulation data for the island of Saipan as provided by one of the bidders to the ongoing RFP as compared to a sampling of hourly CUC load. This analysis allows us to estimate the energy and peak demand impact, by island, for each incremental MW of PV capacity that could detract from grid load (with peak demand impacts estimated based on a range of plausible peak times). Energy and capacity associated with any future installations is also being subjected to panel degradation (at 0.75% per year) to arrive at a more realistic representation of potential future impacts.

Leidos has also discussed the outlook for increased penetration of distributed PV with both CUC and the National Renewable Energy Laboratory (NREL) representative for the IRP. As a result of these conversations, we were able to obtain additional insights regarding anticipated[6] distributed PV additions in the near term, which could include one or more of the following systems (each of which is anticipated within the 2015/2016 timeframe):

- Public School System, Marianas High School: ~95 kW
- CNMI Farmer's Co-Op: ~30 kW
- Commonwealth Healthcare Corporation: ~2 MW
- Residential Accounts: ~278 kW

Additionally, according to NREL, it has been discussed that the Hospital (as listed above) is planning on a large system and plans to net meter the system. However, at this time, they do not have funds that would allow them to do so, nor a contract or clear path to the development of such a contract or probable access to grants that would build the size of the system they need to net meter.

Based on this data exchange, as well as additional discussions regarding scenarios with CUC, the following approach will be taken to develop alternative scenarios for PV adoption (<u>note: such scenarios will not be developed until after the completion of the screening analysis described further below and such scenarios are not contemplated as part of Appendix A of this document</u>):

- A high distributed PV adoption case will be produced that includes the assumption that the projects above are actually instituted;

[5] Additional load scenarios as suggested by NREL related to demand growth increases of an organic nature commensurate with the added hotel load or a less conservative estimate of hotel actualization may be explored after the completion of the screening analysis.

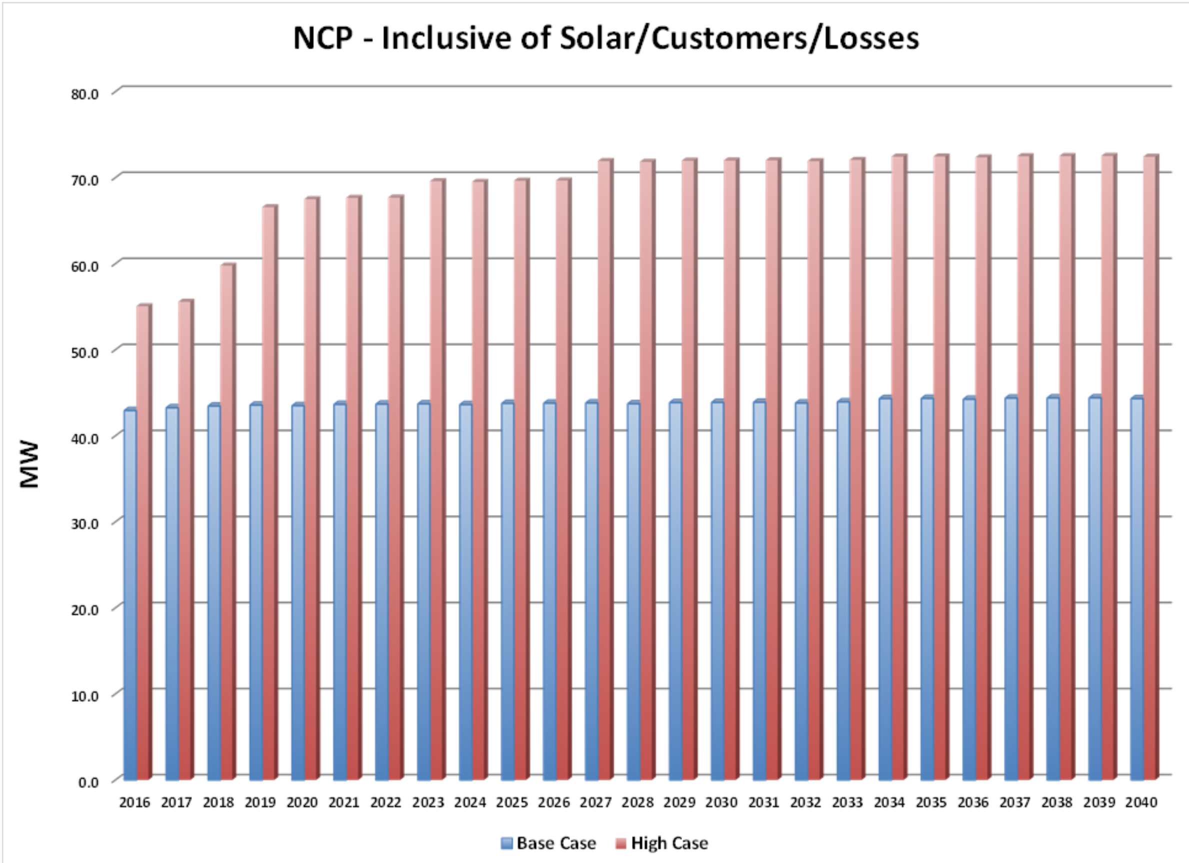
[6] Subsequent to development of the Base Case and High Case, CUC provided additional updated information on currently installed distributed solar capacity on Saipan which represents a minor difference relative to capacity assumed for the Base Case. This new information will be taken into consideration during the PROMOD modeling.

- This scenario will also assume that the "upper bound" of distributed PV installations will be capped by the estimated amount of intermittent generation[7] that the current grid can withstand without significant upgrade costs, or no more than 5 MW AC[8], and
- The diffusion of PV capacity over time will be based on a reasonable diffusion curve constructed by Leidos that balances the amount of intermittent generation associated with distributed resources with the amount of PV being modeled that is of a utility-scale as based on the bids received through the procurement process (as described further below).

As noted above, such sensitivities will not be executed until after the screening process is completed (see further below), which will also uncover other potential resource options that could work to reduce grid load. The projections summarized in Appendix A of this document are reflective of the Base Case and High Case absent such considerations, because it is not possible to know in advance of the screening analysis how much utility-scale PV is anticipated to be economical/practical to model, and because basing the PV uptake on the information gleaned from the screening will limit unrealistic and arbitrary PV scenarios.

The graphic below summarizes the CUC-level projected non-coincident peak demand (NCP) for both the Base Case and the High Case over the Study Period on a "gross" of losses basis (i.e. with losses included). Detailed forecast tables and graphics for energy and demand across cases can be found in Appendix A. Note that the slight increase in load in the latter part of the Study Period is related to the incorporation of the degradation of existing rooftop PV installations.

[7] Based on the existing renewable integration study performed by KEMA, which is subject to some uncertainty but is assumed to be an appropriate basis for IRP-level planning assumptions regarding the existing grid.
[8] AC = alternating current



In addition to the above issues, it should be noted that the impact of any "demand-side management (DSM) as a resource" option that we may parameterize (as based on the DSM portfolio suggested below), as well as any other load related scenarios (tourism, etc.) that we may want to examine downstream will be produced as warranted by the production cost modeling. Refer to the Production Cost Scenarios subsection below for details related to the overarching combination of loads/resources that Leidos proposes will be modeled.

Appendix A of this document summarizes the Base Case and High Case Load Forecast results. As the Assumptions Document evolves, subsequent cases will be added to Appendix A as appropriate. Appendix A also shows the Base Case load forecast without the inclusion of any discrete loads for reference purposes (which reflects only organic growth projected econometrically).

With regard to developing an hourly load shape for CUC, limited hourly generation or sales data was available to develop a Typical Meteorological Year ("TMY") for the purposes of the IRP assumptions. Nine non-consecutive months of hourly generation data beginning in May of 2013 and ending in July of 2014 for Power Plant 1 and Power Plant 2 was provided by CUC and compiled by Leidos. Leidos then derived hourly shapes from missing periods using daily peak generation data (day and night peaks) provided by CUC and daily generation totals to complete an annual hourly load shape for the island of Saipan. This was further supplemented by a follow-up data dump of hourly data provided by CUC to finalize the Saipan hourly profile. Hourly load and generation data was not provided for Tinian or Rota. The derived 2013/2014 shape will be used in the PROMOD® modeling as the annual load shape for all years of the IRP study period for each island.

Capacity Reserve Margin

Following the decline in electricity demand since 2005, CUC's three systems have large capacity reserve margins (i.e. are significantly long on existing generating capacity). Based on discussions with CUC, the IRP reserve margin will preliminarily be based on the assumption that CUC must maintain backup resources to supplant its entire existing grid load, which amounts to a reserve margin of 100 percent. This reserve margin is based on the state and estimated reliability of CUC's existing asset base. As a function of bids received during the procurement, it may become possible to reduce the reserve margin based on a high-level evaluation of the resultant reliability improvements associated with new capacity coming online. This is of particular importance with respect to the impact on capital costs that would result from any scenario wherein CUC's existing asset base was to be replaced in its entirety (as CUC would have to eventually procure twice as much capacity as was needed relative to their load).

Fuel Forecasts

The IRP requires an annual fuel price projection for the primary fuel type consumed by the existing diesel generating units that produce power for CUC, No. 2 Fuel Oil (or LFO), as well as the lubricating oil consumed in each diesel unit. Additionally, based on input from CUC and the results of the stakeholder process, a heavy fuel oil (HFO) scenario is desired to be investigated, as well as a scenario involving liquefied natural gas (LNG). Each of these fuels has been subject to either a new bid as a result of the procurement process and/or a generic scenario developed based on Leidos estimates as noted further below. Consequently, Leidos has worked to project a delivered fuel cost for each fuel on a by-island basis.

Various approaches were considered as a basis to project CUC's future fuel and lube oil costs, including a contract-review based approach for No. 2 Fuel Oil that was predicated upon existing CUC contracts. However, due to the proprietary nature of certain indices within the contracts and CUC's feedback regarding the low likelihood of obtaining such proprietary indices, this approach was abandoned in favor of a more simplified structure that is predicated upon the following steps for each fuel:

(i) Information on existing baseline costs by island were derived from the levelized energy adjustment clause ("LEAC") spreadsheet provided by CUC's rate consultant that covered monthly pricing detail over the period May 2015 – October 2015. This spreadsheet model compartmentalizes existing commodity costs from other key fees that impact delivery to Saipan, Tinian, and Rota for No. 2 diesel fuel. Costs delineated in the spreadsheet include shipping and fixed add-on costs, as well as warfage fees, an oil spill tax, a beautification tax, and a gross receipts tax. This information formed the basis for benchmarking existing commodity costs and for determination of the adders and taxes to apply to each future year of the Leidos commodity forecast to arrive at landed (or delivered prices) for oil.

Leidos then researched and prepared a delivered commodity price projection for all three fuels, generally based on a blend of short to medium term futures information and the Energy Information Administration (EIA) 2015 Annual Energy Outlook (AEO), which provides long range commodity projections of all key fuels. The commodity cases were used to forecast long-range commodity prices under the following AEO cases using both mainland inflation (2.3%) and Saipan inflation (3.3% as noted above). For the HFO projection, Leidos has selected a sulfur content that has been determined to be least likely to be subjected to environmental compliance challenges (or 0.3% sulfur content)[9]. The dual inflation cases are intended to capture the uncertainty inherent in the implied inflation rate deployed by the EIA in developing their real prices, which must be nominalized for discounted cash flow purposes within the IRP. The AEO cases considered and summarized in Appendix C of this document are as follows:

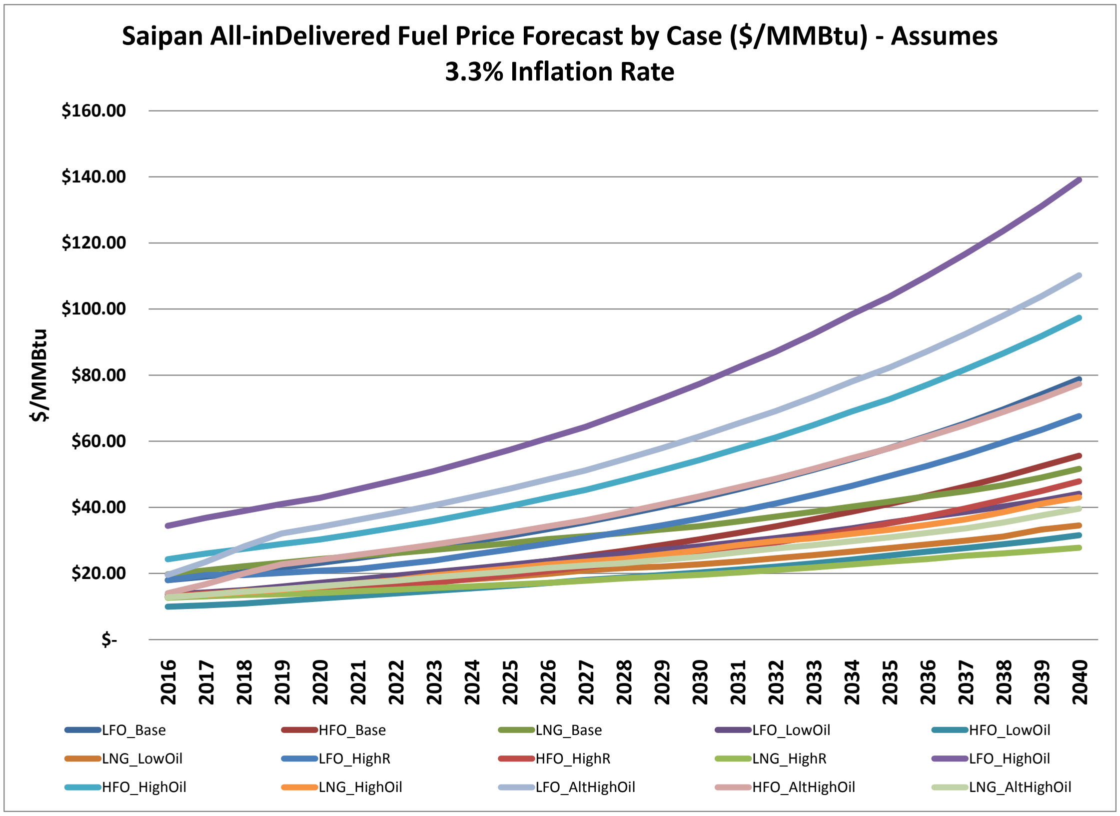
- Base Case
- High Oil Case (reflective of higher oil prices) – note that this case was supplemented by a capped high oil case as prepared recently by Leidos for Guam given the very high oil prices indicated by the AEO (or the "Alternative High" Case)
- Low Oil Case
- High Resource Case (which reflects the assumption of high resource extraction availability for both oil and natural gas over time)

For LNG, Leidos estimated additional adders related to bulk delivery of LNG to Saipan (with ISO container delivery to Tinian and Rota as described in the Future CUC Resource Options subsection below). These adders included allocations for transportation charges, a transportation fuel retention percentage, and liquefaction tolling charges and shipping charges. For delivery from Saipan to Tinian and Rota, the percentage differentials in delivered No. 2 oil costs from the LEAC spreadsheet were applied to landed Saipan LNG costs to derive the appropriate differentials for LNG delivery to Tinian and Rota, under the assumption that a similar barge for ISO delivery and similar/the same staffing could be deployed to deliver LNG to those islands.

The delivered fuel forecast for each fuel was then prepared by combining the adders and taxes applicable to each fuel with the commodity projection for each AEO case over the course of the Study Period.

Fuel contents for No. 2 fuel oil and heavy fuel oil were assumed to be 5.76 and 6.287 million British Thermal Units (MMBtu) per barrel. Additionally, it should be noted that certain taxes or adders are the same across each island. The graphic below compares the delivered fuel prices for each fuel for the island of Saipan as an illustrative example of the range of fuel prices projected.

[9] Leidos has conducted a planning-level environmental review of the potential challenges associated with permitting and deployment of units running on HFO as a result of existing US Environmental Protection Agency regulations. Such details are only relevant to the results of the IRP to the extent the HFO solution, inclusive of all compliance costs, is deemed economical relative to other options.



Appendix C of this document summarizes, in tabular format, the resulting fuel projections for No. 2 Fuel Oil, HFO, and LNG on a by-island basis using the assumed CUC inflation rate and under the Base Case, High Oil Case (including the adjusted High Case based on Guam baselines), Low Oil Case, and High Resource Case from the 2015 EIA AEO. Leidos will work with CUC as part of the scenario process to identify the specific fuel cases to be deployed for the screening analysis as well as the more detailed production cost modeling within PROMOD.

Lubricating Oil

The diesel generating units operated by both CUC and Telesource on Tinian consume varying quantities of lubricating oil based on spreadsheet data provided by CUC. Lubricating oil costs are included in the CUC fuel adjustment clause, and have been included in the overall operating cost projection for existing and future resources as based on the LEAC worksheet provided by CUC's rate consultant. Growth in lube oil cost has been tied to the growth in the core commodity component of the existing fuel oil used by CUC. Appendix C provides a tabularized summary of lube oil costs in dollars per gallon for Saipan and Rota across each of the fuel cases noted above (under the 3.3% inflation rate assumption). Note that because the Tinian assets are subject to power purchase agreement charges outside of fuel, lubricating oil costs are included in the variable O&M costs in Appendix B for Tinian units.

HFO Compliance Costs

In addition to the cost of HFO as a fuel, there are potentially significant environmental compliance costs associated with burning HFO. Leidos has performed a planning-level review of the implications of the United States Environmental Protection Agency (EPA) regulations with regard to getting permitted for use of HFO. Our review has included discussions with NREL as well as a representative from EPA. ***While the extent of our review does not in any way constitute a regulatory opinion on the ultimate plausibility of HFO deployment***, it is clear from our review and from the significant stakeholder interest in modeling HFO as part of the IRP that such a scenario cannot be automatically assumed to be impossible. As a consequence of this finding, Leidos has assumed herein that the materiality of the actual act of compliance is secondary to the development of reasonable assumptions that attempt, as best as possible given the limitations inherent in a lack of prior HFO deployment and precedent, to capture the physical compliance technologies and associated cost implications for inclusion in the modeling process.

In order to develop such assumptions, Leidos has interfaced with a vendor that is familiar with existing (legacy) HFO deployments. We have also relied upon our engineering team's suggestions for the engineering and waste stream requirements for deploying HFO. Based on this review, the potential of installing equipment on the front end to clean the sulfur out of the oil is not practical based on the size of the units contemplated for CUC.

The capital cost addition for back end scrubbers (and Selective Catalytic Reduction and carbon monoxide (CO) catalyst) are anticipated to double the cost of an engine in the size range contemplated in this IRP. Further, the operational complexity increases dramatically as the exhaust gas would need to be cooled to support scrubber operations. Furthermore, more water would be needed, reagent such as lime would need to be brought to the island, and there would also be waste streams (solid waste and wastewater) to manage. All of the auxiliary equipment will drive up the use of power at the facility (station load) and negatively impact the heat rate of the asset in question. Technically competent staff would also be required to support operations, which may require additional training and/or pose a risk in terms of a given bidder's experience with HFO deployment.

In order to model the economic implications of an HFO scenario as objectively as possible, Leidos will assume the following additional costs for the HFO-centric bid described above:

- Scrubber/Cooler/Baghouse – estimated cost of $20M
- Auxiliary power (and associated cost): 1.5 MW per operating hour (based on a system with ID fan, which is supplanted with cooling water pumps or chillers)
- Increased O&M: $2/MWh
- Increased capital costs associated with compliance: $1 million every 3 years (or $333,000 per year)

To the extent such costs can establish HFO as less economically attractive than the alternative bids, the costs assumed above can be assumed to be sufficient in terms of capturing the economic and logistical complexity associated with HFO deployment. ***Based on discussions with CUC, Leidos will not pursue additional cost estimates for items such as cooling water, lime reagent, source water and disposal costs, and lime commodity, shipping and disposal costs but will note such costs as needing to be subjected to further due diligence to the extent that an HFO-centric expansion plan appears economically attractive in the context of the final IRP report.***

Existing CUC Generating Assets by Island

CUC was the primary source for CUC's unit characteristics, which are summarized at a high level in the table below. Leidos has performed a review of these characteristics to identify potential areas of concern or anomalies relative to performance characteristics for similar units with which we are familiar, and we have worked with CUC and CUC's rate consultant to obtain additional data and make certain adjustments, as appropriate. Appendix B contains detailed operating assumptions for each CUC generating unit by island. Refer to Appendix B for more complete summaries of existing cost and performance information that has been compiled in order to perform dispatch modeling of the CUC system on a by-island basis.

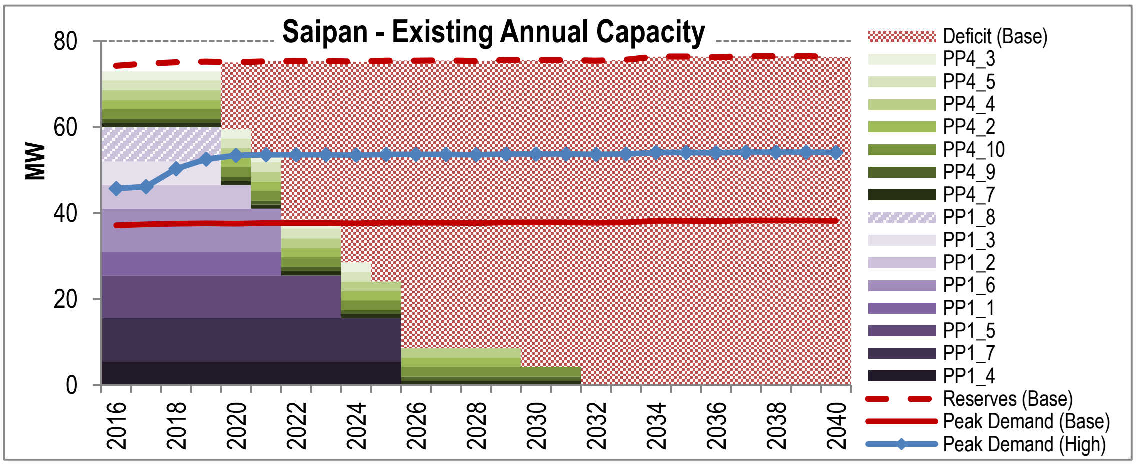
Current CUC Generation Supply

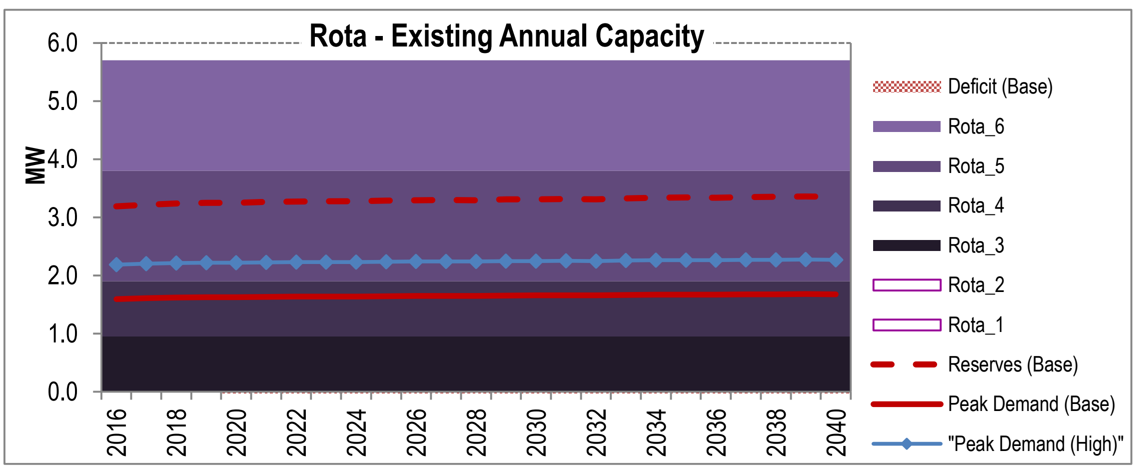
Plant	Unit	In-Service Year	Firm Capacity	Unit Type	Status	Heat Rate	Fuel Type
			MW			MMBtu / MWh	
Power Plant 1	1	1979	5.5	Reciprocating	Operating	9.177	No. 2 Oil
Power Plant 1	2	1979	5.5	Reciprocating	Operating	9.150	No. 2 Oil
Power Plant 1	3	1979	5.5	Reciprocating	Operating	9.402	No. 2 Oil
Power Plant 1	4	1983	5.5	Reciprocating	Operating	9.243	No. 2 Oil
Power Plant 1	5	1989	10.0	Reciprocating	Operating	9.337	No. 2 Oil
Power Plant 1	6	1989	10.0	Reciprocating	Operating	9.431	No. 2 Oil
Power Plant 1	7	1991	101.0	Reciprocating	Operating	9.237	No. 2 Oil
Power Plant 1	8	1991	8.0	Reciprocating	Operating	9.295	No. 2 Oil
Power Plant 2	1	1972	1.9	Reciprocating	Out-of-Service	9.500	No. 2 Oil
Power Plant 2	2	1972	1.9	Reciprocating	Out-of-Service	9.500	No. 2 Oil
Power Plant 2	3	1972	1.9	Reciprocating	Out-of-Service	9.500	No. 2 Oil
Power Plant 2	4	1976	1.9	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 2	5	1976	1.9	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	2	1957	2.1	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	3	1956	2.1	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	4	1972	2.3	Reciprocating	Standby	9.746	No. 2 Oil
Power Plant 4	5	1977	2.3	Reciprocating	Standby	9.746	No. 2 Oil
Power Plant 4	7	1998	0.95	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	9	1998	0.95	Reciprocating	Standby	9.500	No. 2 Oil
Power Plant 4	10	1980	2.3	Reciprocating	Standby	9.746	No. 2 Oil
Rota	1	NA	2.3	Reciprocating	Standby	10.10	No. 2 Oil
Rota	3	1998	2.3	Reciprocating	Standby	11.10	No. 2 Oil
Rota	4	1998	2.3	Reciprocating	Standby	11.10	No. 2 Oil
Rota	5	2010	2.3	Reciprocating	Standby	9.80	No. 2 Oil
Rota	6	2010	2.3	Reciprocating	Operating	9.80	No. 2 Oil
Tinian	1		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	2		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	3		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	4		2.3	Reciprocating	Operating	9.746	No. 2 Oil
Tinian	5		4.5	Reciprocating	Operating	97.46	No. 2 Oil
Tinian	6		4.5	Reciprocating	Operating	9.746	No. 2 Oil

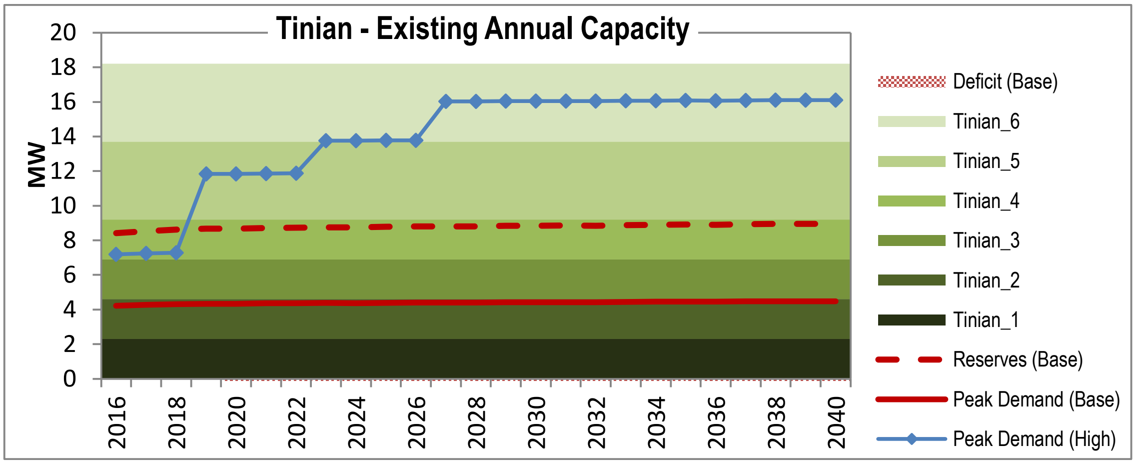
CUC Capacity Gap Analysis

Based on the information provided by CUC regarding the hierarchy of potential asset retirements for each island's assets (if applicable), Leidos has prepared indicative capacity gaps by year for each island. The capacity gap analysis is predicated upon a staggered retirement of existing CUC assets in order to determine the total capacity gap (or capacity requirements) of CUC inclusive of the assumed reserve margin in each year of the study period. By design, the capacity gap analysis is indicative only, as the bid and procurement process may result in assets whose prices and transactional structure are based on large-scale capacity additions that would come online in a single year, with existing CUC assets remaining available on a standby or emergency basis until CUC is comfortable that the new generation can reliably serve CUC's load.

The three figures that follow summarize anticipated capacity gaps by year for each island, with both the Base Case and High Case load forecasts superimposed on existing CUC capacity resources for Saipan, Tinian, and Rota respectively as well as reserves based on the Base Case load forecast. The table that follows summarizes the estimated capacity gap by year for each island over the Study Period based on the Base Case load forecast and the aforementioned 100 percent reserve margin.







Estimated Capacity Gap by Year[10] (MW) by Island

Year	Saipan	Rota	Tinian
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	-	-	-
2020	15.58	-	-
2021	21.32	-	-
2022	36.86	-	-
2023	36.90	-	-
2024	46.73	-	-
2025	51.36	-	-
2026	66.89	-	-
2027	66.92	-	-
2028	66.75	-	-
2029	66.98	-	-
2030	71.40	-	-
2031	71.43	-	-
2032	75.46	-	-
2033	75.68	-	-
2034	76.42	-	-
2035	76.44	-	-
2036	76.26	-	-
2037	76.48	-	-
2038	76.50	-	-
2039	76.52	-	-
2040	76.34	-	-

[10] The load forecast accounts for the number of hours in a given year, which impacts peak demand as a function of the relationship between energy and load factor used to derive annual peaks.

As shown above, Rota and Tinian are not anticipated to require additional capacity under Base Case load forecast conditions inclusive of reserves. As noted earlier in this document, alternative load cases will inform capacity requirements as part of the PROMOD modeling. The capacity gap analysis, which is indicative in nature, will help inform the final scenarios to be modeled as part of the detailed production cost simulations within PROMOD.

Stochastic Simulations of Load and Fuel

Insufficient historical data exists for CUC's fuel costs and CUC's hourly and monthly load data to support representative volatility estimates of such inputs within the PROMOD model's stochastic simulation engine. Consequently, fuel volatility will be represented by the modeling of the alternative AEO fuel cases as described above, in partnership with CUC in a manner that carefully bounds the number of simulations while capturing a reasonable range of potential fuel futures. For annual level energy and peak demand data, the historical standard deviation (as a percentage of the average over a limited historical period of available data) of each determinant was calculated to be 12% and 13%, respectively. These estimates will be subjected to test runs within the PROMOD model in order to determine whether judgmental changes are warranted to limit load volatility from becoming untenably large within the simulations. Adjustments will be made based on prior resource planning engagement experience.

Proposed Renewable Generation Supply

The proposed American Capital Energy (ACE) solar PV projects on Saipan and Rota will be modeled using existing terms and conditions including price, installed capacity and commercial operations dates. Hourly PV generation profiles supplied by the developer, if available, or proxy profiles based on the PVSyst simulations provided by bidders to the RFP, will be used in the production cost simulations.

Future CUC Resource Options (Supply-Side)

Future resource options available to CUC have been derived from the following three sources:

- Detailed RFP responses by individual bidders, which include cost, performance, and transactional details for a range of generating resources; the RFP responses have been subjected to a detailed and rigorous qualification process, after which a subset of the bids was deemed qualified for further evaluation. The domain of resources for the bids that were qualified include solar generation, energy storage, traditional diesel fired generation deploying both LFO and HFO, and a major maintenance project related to CUC's existing generating units.
- A review of the most practical demand-side management options available to CUC for endorsement as based on Leidos' review of available information – as there were no bids received that contained DSM, the DSM Portfolio Definition

subsection below represents the entirety of programs that will be screened and considered for the IRP.

- A review of IRP stakeholder concerns as mapped against other plausible resource expansion options of a supply-side nature, which resulted in the identification of an LNG based solution as an additional option that was to be parameterized based on cost estimates compiled by Leidos.

This subsection summarizes the bids received in tabular form and with text to describe the nature of the transaction bid in each case, and also provides a description of the LNG solution as contemplated by Leidos. All of the detailed cost and performance assumptions and the terms associated with each option (i.e. the number of years assumed for modeling the specific transaction) across each of the bids (some of which contain more than one specific option or technical solution) is contained within Appendix D of this Assumptions Document in tabular format and should be referred to as a supplement to the descriptions herein. For confidentiality purposes, the names of bidders have been removed and each solution is defined with a bidder number in order to facilitate review of this document without disclosure of bidder names by removing the brackets.

It is important to note that other potential supply-side resource options and renewable options that did not receive any specific RFP bids and/or have been determined to be infeasible on Saipan due to the size of the load on each island, including resources such as biomass, waste-to-energy, coal-fired generation, hydroelectric generation, nuclear generation, and wind generation, are not considered further herein. Leidos has relied upon the stakeholder process conducted as part of the IRP and the specific bids received as part of the RFP to inform the domain of resource options, with the LNG option being added into the resource base due to the potential cost savings that could be provided and as based on stakeholder interest in such a potential solution. However, the LNG assumptions delineated herein and in Appendix D are not associated with a specific bid and should be interpreted accordingly.

The table below summarizes the qualified bids received that will form the basis of the scenarios, screening analysis, and ultimate PROMOD simulations. As noted above, bidders are masked.

Bidder	Generating Resource Type/Description	Maximum Capacity Offered
Renewable 1	A range of solar generation, both with and without battery storage and including optionality with regard to site control at specific feeders	Range of bids covers 1MWac up to 10 MWac[11]
Renewable 2	Solar generation only	10 MWac

[11] “ac” denotes alternating current capacity.

Bidder	Generating Resource Type/Description	Maximum Capacity Offered
Thermal 1	Traditional diesel generation running on HFO as a single project (all capacity added at once)[12]	30 MW (nominal rating of asset proposed); reflects installation of 4 diesel units with a nominal rating of 8.73 MW each
Thermal 2	Traditional diesel generation running on LFO as a single project (all capacity added at once)	4 diesel units, each with a nominal rating of 8.73 MW
Thermal 3	A range of remediation of CUC's existing asset base and new diesel generation running on LFO, with pricing based on 3 alternative solutions[13].	Alternative Solution 1: major maintenance on CUC's existing units subsequent to an onsite review of the current condition; <u>note that this option was removed from further consideration as a result of lack of appropriate cost data</u> Alternative Solution 2: installation of 4 diesel units with a nominal rating of 8.7 MW on a fast-track basis, with additional allowance for 2 more units at CUC's discretion Alternative Solution 3: 70 MW (nominal rating of powerhouse with additional capacity expansion relative to Alternative Solution 2); still based on increments of 8.7 MW with a maximum expansion of 12 units

Following is a description of the transactional nature of each of the above bids, which will serve as the basis for modeling each bid as well as for identification of potential risks and challenges associated with a given bid as will be described in the final report (note: more detailed cost and performance information can be found in Appendix D):

- Renewable 1 is predicated upon a long-term power purchase agreement with CUC for a term of up to 25 years with no cash contribution required on the part of CUC. Renewable 1 would finance, construct, and operate the project in whichever configuration and combination of capacity, storage, and site control desired, and would charge CUC a set rate per MWh of energy delivered with a 1% annual

[12] Inquiries to bidders were made regarding the possibility of a more gradual increase in capacity. However, bidders' responses indicated that such a configuration would generally be more expensive given the additional soft costs associated with gradual installation, and consequently, certain bidder responses reflect "all-in" capacity projects.
[13] A 4th alternative solution was proposed but then retracted by this bidder due to lack of cost information.

escalation of the rate. All costs associated with the project would be paid by the developer and decommissioning would also performed by the developer. Costs differ to some extent as a function of the amount of capacity and configuration selected. Refer to Appendix D for further details.

- Renewable 2 is predicated upon a power purchase agreement with a term of up to 25 years at a set price per MWh of energy delivered, with 0% annual escalation. Pricing is provided both with and without the benefits of federal investment tax credits (ITC) and certain depreciation benefits. The lower tier of pricing is contingent upon completion of construction by December 31, 2016. Both prices reflect 0% annual escalation and no cash contribution on the part of CUC. The developer would finance, construct, and operate the facility and charge CUC on the basis of the power purchase agreement. <u>It is important to note that as part of bidder follow-up, it was determined that the cost of storage for ramp rate control for the amount of capacity bid into the system was quoted to reflect a 10% increase in the indicative PPA pricing provided by this bidder, which will be incorporated into the screening analysis</u>.
- Thermal 1 is predicated upon the bidder constructing, financing and operating the plant (through the use of an operation and maintenance firm), which is assumed to operate over the entire Study Period based on extension of the power purchase agreement proposed. Charges would be recovered as a function of an independent power producer (IPP) structure wherein the bidder would recover charges associated with the facility, including (i) capacity charges that capture debt service and fixed operation and maintenance (O&M) charges and (ii) variable operating and maintenance charges outside of fuel. Capacity and fixed O&M charges were obtained via bidder follow-up based on both a 15 year and 25 year arrangement, and both will be considered as part of the screening analysis. Capacity and variable charges would be subjected to 2.3175% escalation annually. The cost of fuel would be predicated upon the delivery of fuel to the bidder by CUC. Additionally, as the bidder has not adequately captured the cost of environmental compliance associated with the proposed fuel, Leidos will estimate the additional capital cost associated with equipment and environmental compliance activities (as described elsewhere in this document) and add those estimates into the modeling for this bid.
- Thermal 2 is predicated upon an engineer, procure, and construct (EPC) bid to develop the project, and a follow-on operation and maintenance arrangement that would allow the bidder to operate the plant over the entire Study Period. In this configuration, financing of the project would be dependent upon CUC, and the bidder would serve solely in an operation and maintenance capacity, with associated fixed and variable charges to recover operational costs. Fuel delivery would be based on CUC fuel delivery to the project. The bidder has provided terms and conditions associated with the operation and maintenance contract that reflect escalation rates on such charges equal to 1% over and above the prior year's US Gross Domestic Product Implicit Price Deflator.
- Thermal 3 provides multiple alternatives for future capacity and major maintenance. Each solution that has been carried forward into the modeling (which

excludes Alternative 1 due to lack of cost data and Alternative 4 due it being withdrawn by the bidder) is dependent upon (i) a capacity charge that reflects recovery of the debt service costs of the solution (bid in as a monthly charge over the proposed financing period of 20 years, which will go to zero over the remaining Study Period years), (ii) charges intended to cover other fixed operating and maintenance charges, and (iii) variable operating and maintenance charges. As with all other thermal solutions, fuel delivery would be the responsibility of CUC as an additional cost. Cost escalation rates for charges are based on 1.5% over and above the prior year's US Gross Domestic Product Implicit Price Deflator, beginning with the second year of billing. The ultimate financing of a given alternative is ostensibly based on bidder financing; however, the financing of a given alternative is also based on securitization and guarantees by CUC and/or the government; for IRP modeling purposes, it will be assumed that the financing will take place and that the bidder will serve in an IPP capacity, collecting charges commensurate with the capital cost, fixed and variable cost associated with the project.

It is critical to note that the ultimate transactional details of a given option will be subject to downstream negotiations between CUC and a given bidder to the extent a bid is determined to be economical and in alignment with the IRP objectives, the details of which cannot be foreseen at this time and which fall outside the scope of the IRP. Additionally, certain bidders have made site-specific assumptions within their pricing, while others have not and have provided site-neutral pricing that assumes a standard or minimal amount of site remediation, property taxes, and/or leasing costs. ***However, it can be assumed that each bidder intends to remain in alignment with their proposed terms and conditions as well as their pricing as a foundation for successful project deployment and contractual negotiations, and the modeling performed during the IRP will be predicated on this assumption (i.e., that the bidder pricing includes embedded charges that reflect some amount of execution risk on the part of the bidder related to unforeseen conditions, exclusions of project envelope elements, and other deployment nuances that will be pursued if and only if CUC determines to move forward with a given bidder).***

LNG Option Assumptions

As noted above, there were no bids received that included LNG as an option. Given that LNG was determined to be of interest to IRP stakeholders, as has been done with the proposed demand-side management portfolio, Leidos has prepared planning level assumptions for an LNG centric solution. These assumptions are summarized in Appendix D. The bullets that follow represent the core elements of the proposed LNG solution:

- LNG would be delivered in bulk to Saipan, which requires a dedicated LNG facility to be built on the island. Regasification and shipment to Tinian and Rota, to the extent such islands can support the scale of load that is commensurate with gas-fired or dual-fuel generation, which based on Leidos' review is tractable given the size of units that could be constructed, would be based on ISO container delivery.

- Under the assumption that the existing CUC fleet is prohibitively old to consider a conversion to gas, new dual-fuel capacity for Saipan would be constructed in addition to the LNG facility.
- The capital cost of the LNG facility would be an added cost over and above fuel delivery and the capital cost of the new gas-fired resources as part of an integrated solution that assumes that CUC would derive the majority of their thermal resource needs from gas (i.e., that there would be limited to no remaining LFO used across the islands). Given the terms and conditions of the existing Tinian PPA, it is unlikely that LFO use would be eliminated entirely over the Study Period, and Leidos will take care to model the costs associated with the Tinian PPA and the associated obligations for the "all-in" LNG deployment case. However, the deployment of LNG is only plausible as a function of a certain baseline of fuel demand that would hypothetically provide sufficient incentive for developers to commit to the infrastructure required. We have estimated the annual fuel requirements as a function of the capital cost estimate for fuel infrastructure associated with this potential solution.
- As an added illustrative scenario relative to the "all-in" transition to LNG as described above, Leidos will also prepare a scenario that only encompasses a transition for Saipan (with a proportional reduction in fuel infrastructure capital cost), with the understanding that such a scenario could have certain implications relative to the impact on fuel-oil pricing and delivery to Tinian and Rota, the estimates of which fall outside the scope of this IRP.

Distribution System Costs

Leidos assumes that costs for distribution system impact analysis and any distribution system upgrade costs associated with a particular deployment option that involves new resource types is the responsibility of the RFP bidder to provide as part of their response. Leidos reserves the right to follow up with bidders related to this information, as appropriate. Additionally, CUC owns and maintains an existing distribution system model that can be used to perform power flow and stability analyses, and there are dedicated CUC personnel that will be made available to Leidos as part of the evaluation of bids. Additionally, CUC has provided an existing study regarding renewable integration that contains framing information regarding potential distribution system impacts for a given installation. These resources will be leveraged on a bid-by-bid basis to ensure that an adequate accounting of any distribution system costs is included in the total cost of a given bid.

Demand Side Management (DSM) Options and Portfolio Definition

DSM options (which can include energy efficiency (EE), demand response (DR), conservation, and other behavioral programs), will be considered in parallel with traditional supply-side resource options in an integrated and holistic fashion. It was initially anticipated that there would be a small likelihood that bids associated with the ongoing RFP/Procurement would reflect integrated solutions that included some amount of DSM. None of the bids received reflected any DSM. The following is the roadmap that has been followed to ensure that DSM is treated fairly and transparently within the IRP:

- Energy Efficiency (EE) programs are a requirement of Senate Bill 15-38. Since there were no bids received that reflected DSM, there was no need to examine bids to determine the extent to which they support compliance with Senate Bill 15-38. Additionally, Senate Bill 15-38 was deemed “not determinative” in terms of the evaluation of a given program, the assumptions for which have been based on planning-level DSM investigations conducted by Leidos.
- Given that compliance with the legislation is not a specific requirement, Leidos will perform a high-level DSM screening using our proprietary DSM decision-making model, and select only those DSM measures that are economical based on the Rate Impact Measure and Total Resource Cost cost-benefit framework, which are industry-standard metrics for determining the economic competitiveness of a given DSM portfolio element, which will then determine the ultimate inclusion (or lack thereof) of a given DSM portfolio element. The DSM measures that have been investigated and are suggested for purposes of the screening are discussed in the DSM Portfolio Definition subsection below.
- The load (energy and peak demand) impacts of any DSM measure deemed economical and worthy of deployment will be modeled as a reduction to the load forecast prior to the onset of production cost modeling. The cost associated with the DSM portfolio (all included DSM measures) will be added as a line item to the production cost simulations associated with serving the remaining grid load.

DSM Portfolio Definition

As part of the IRP, Leidos was tasked with evaluating a targeted set of energy efficiency programs that represent “low hanging fruit” in terms of economic potential and impact on Saipan and CNMI energy consumption. Specifically, the Leidos review is focused on defining a representative, simple program for each of the residential and commercial sectors that have a high probability of success, are low cost, and will motivate customer interest in further energy efficiency measures. As noted above, these initial programs will be subjected to a DSM screening. To the extent such screening results in a positive estimated program impact from a cost-benefit perspective, these programs will be incorporated into the downstream production cost scenarios, with associated costs added into the overall CUC power supply cost estimates.

After review of available National Renewable Energy Laboratory analyses and CUC information about CNMI energy consumption, Leidos recommends an initial set of programs for residential and commercial customers with the following characteristics:

- A residential program that emphasizes easy, self-installation of water and lighting measures distributed via a free kit.
- A commercial program that address significant energy end uses for hard to reach small and medium sized businesses—lighting and refrigeration measures

administered via a 'turnkey' direct install program; energy efficient technologies suited to prescribed energy savings estimates and unit incentives that are clear to the customer and require minimal technical expertise to administer.

- Program delivery approaches that utilize existing equipment distributors, contractors, and other trade allies in the 'midstream' of the market, motivating greater participation and facilitating evolution of programs into more advanced offerings. Targeting the midstream directs outreach and other administrative spending to a limited audience, who can then bring the program information to end-use customers.

The subsections below define the suggested residential and commercial programs and provide the key performance and cost assumptions underpinning each portfolio element. Leidos will work to screen these measures in parallel with the supply-side resource screening.

Residential Sector Programs

Research indicates that air conditioning, water heating and appliances are top residential end uses in an island climate. There may already be fair uptake of compact fluorescent lights (CFLs) and light emitting diodes (LEDs) in CNMI due to rapidly falling prices and older technology phase-outs in the mainland US. Increasing the penetration of LEDs should be included as a program goal. Based on feedback from NREL, CFL proliferation should be avoided based on the fact that CFL bulbs contain toxic mercury vapor and cannot be landfilled, and the cost of safe recycling is high, so the focus of lighting efforts herein is on LEDs. The following are the proposed programs/measures for evaluation, followed by estimated parameters for evaluation purposes, including an assumed annual participation rate (defined as the number of rebates per year per portfolio element that would be distributed[14]):

- **Residential LED lighting** – A point-of-sale rebate or cost buy-down for LED screw in retrofit bulbs, delivered by local hardware retailers, will improve the efficient lighting market and sales for the retailers, make the experience easy for the customer, and generate customer interest in other efficiency opportunities. Promotion of the offering can be largely housed at the retail site, minimizing advertising costs.

- **Energy Savings Kit** – A free kit containing a low flow shower head and faucet aerator to be offered at retail sites, public events in which CUC could participate, or distributed by a third party contractor.

Parameter	Residential LED Lighting	Energy Savings Kit[15]
Measure Description	9 W screw base LED lamp	A low flow shower head and faucet aerator
Baseline Description	45 W incandescent lamp	standard flow fixtures

[14] Uptake is assumed to be flat on an annual basis, as a result of the expectation that new installs will be minimal/negligible as compared to replacements.

[15] Statistics in this column represent summations or weighted averages across the elements in the kit.

Parameter	Residential LED Lighting	Energy Savings Kit[15]
Annual Energy Savings per unit (kWh)	23	547
Annual Peak Demand Savings per unit (kW)	0.02	0.43
Capital Cost Differential per unit (incl. install)	$30	$13[16]
Initial CUC Incentive per unit Level[17]	$10	$13 (kit is provided at no cost)
Service Life	15	8
Peak Coincidence (%)	80%	47%
Net-To-Gross Adjustment (%)	75%	60%
Participation Rate (annual units)	276	300

While air conditioning and appliances are expected to be the largest residential electric end uses in the CNMI, Leidos does not recommend launching offerings targeting these technologies. They typically require a larger investment on both the utility and the customer part to administer application reviews and sufficient rebates to move the market; or to purchase and install new units, especially if existing equipment is not at end of life. The suggested lighting and water (heating and conservation) measures are inexpensive, easy to install, and offer immediate benefits.

For the kit offering, Leidos recommends that CUC consider soliciting local non-profit organizations or even local government agencies to distribute the measures, possibly install measures in a home visit, and provide outreach and marketing of the program. A locally known and trusted presence not previously affiliated with sending utility bills can lend credibility to the DSM program and may increase market reach and uptake, possibly at lower overall cost than a private contractor.

Commercial Sector Programs

The commercial sector within the CNMI is dominated by the hospitality and government sectors. Top commercial end uses are air conditioning and lighting. A 2011 report suggests that hotels in CNMI have been implementing their own energy efficiency policies. Meanwhile, small and medium-sized service businesses, retail/grocery/convenience, restaurants, etc. are a hard-to-reach market in any geography or climate, and serve both tourism and local residents. Accordingly, the

[16] There may be some small installation cost for certain elements of the kit that would be borne by the participant, but most participants would be qualified to perform the installation themselves.
[17] Incentive levels are initially proposed figures, and will be subject to an iterative process within the cost-benefit analysis to ensure as economically viable a measure as possible, while balancing the benefits to the participants with those to the utility and impacts on non-participants (i.e., subsidies).

following are the proposed measures for evaluation to be offered in a direct install program administered by qualified local contractors, followed by estimated parameters for evaluation purposes, including an assumed annual participation rate:

- Efficient Refrigeration Direct Install – Utility will cover 75% of project cost[18] up to a project cap, for selection, procurement and installation of various refrigeration measures, including:
  - Insulated night covers for open coolers
  - LED strip lighting to replace standard fluorescent strips in coolers and freezers
  - Electronically commutated motors (ECM) to replace standard evaporator fan motors in reach-in cases
  - Anti-sweat heater controls on glass door cooler/freezers
  - Strip curtains to limit cold air exfiltration/warm air infiltration to walk-in coolers/freezers
- Efficient Lighting Direct Install – Utility will cover 75% of project cost up to a project cap, for selection, procurement and installation of various lighting measures, including:
  - LED bulbs replacing halogen down-lighting
  - LED linear tubes replacing standard fluorescent tubes
  - Super T8 tubes replacing standard fluorescent tubes

Parameter	Refrigeration Package[19]	LED Lighting	T8 Fluorescent Lighting
Measure Description	LED case lighting, night cover, ECM motor, anti-sweat heater control	PAR38 or linear LED Lamp	Super T-8 Lamp
Baseline Description	fluorescent case lighting, open bin cooler, standard evaporator fan motor, uncontrolled door heater	Standard Fluorescent or halogen lamp	Standard linear Fluorescent lamp
Annual Energy Savings (kWh)	4,227	178	21
Annual Peak Demand	0.33	0.05	0.01

[18] Preliminary recommendation only. A direct install program might also institute a total incentive cap to design for cost-effectiveness and control budget spend.
[19] For planning purposes, assumes 1 direct install refrigeration package includes 3 lamps for reach in cooler/freezer, 2 anti-sweat controllers , 1 ECM fan motor, 1 lamp for open cooler, and 1 night cover. In practice, some projects may select multiples of only some of these components.

Parameter	Refrigeration Package[19]	LED Lighting	T8 Fluorescent Lighting
Savings (kW)			
Capital Cost Differential (incl. install)	$1,100	$50	$14
Initial CUC Incentive Level[20]	$825	$35	$11
Service Life	15	16	15
Peak Coincidence (%)	80%	40%	40%
Net-To-Gross Adjustment (%)	75%	75%	75%
Participation Rate (annual units deployed)	35	4,000	3,500

Suggestions for future DSM program Enhancement

Starting a DSM program with 'tried and true' efficiency offerings such as lighting, plus obvious warm climate measures like refrigeration retrofits, creates market demand for energy efficient equipment and services that local equipment sellers and service providers will then strive to meet. A simple and limited prescriptive program can also motivate customers to ask 'what else can I do', which will build demand for more complex offerings such as performance-based incentives for custom or whole building new construction projects, behavior motivation initiatives, more advanced training for trade allies, demand response, and other program elements that CUC could assess for inclusion in a growing DSM portfolio.

It is important to note that DSM impacts will be based solely on the measures that pass the benefit-cost tests deployed, and that the resulting DSM savings estimates can then be compared to specific internal long-term targets for DSM performance, if applicable. As the DSM program matures and future measures are added, goal tracking relative to targets can be also be contemplated.

Administrative and Avoided Cost Basis for DSM Evaluation

Administrative Costs and Avoided Costs associated with the residential and commercial programs above were calculated as follows by program:

A full time equivalent (FTE) is assumed to be 1,880 hours and $90 per hour (burdened).

[20] Incentive levels are initially proposed figures, and will be subject to an iterative process within the cost-benefit analysis to ensure as economically viable a measure as possible, while balancing the benefits to the participants with those to the utility and impacts on non-participants (i.e., subsidies).

(i) ***RES_KIT***: A free residential kit for delivery via mail and/or events. Contains a faucet aerator and a low flow shower head. The dollar value of the kit is assumed to be $13. Expected annual participation is 300 kits.

- Assume that half will be distributed via mail: 250 solicit calls * 5 minutes per call/60 min per hour = 21 hours; 150 follow up calls*10 minutes per call/60 min per hour = 25 hours; 0.02FTE on participant solicitation and follow up
- 50 hours per year on tracking and reporting = 0.025 FTE
- 5 community events* 12 hours per event planning and implementation = 60 hours; 0.03 FTE event distribution
- $1,000 for design and in-house production of 1 page program collateral
- $5 per kit to mail 150 kits per year = $750 per year
- $100,000 in Year 1 consulting support for marketing and outreach/implementation

RES_LED: Residential point of sale LED screw in bulb. Gross cost of bulb is assumed to be $30. $10 price markdown at the register. Expected gross annual participation is 276 bulbs.

- Monthly invoice reconciliation, tracking and reporting: 4 hours/month * 12 months = 0.025 FTE
- Minimal marketing expense for signage in stores; maybe a bill insert
- $100,000 in Year 1 consulting support for marketing and outreach/implementation

COMM_LED: Commercial LED direct install (PAR 38 bulb replacing halogen or tube replacing standard T8). Average cost per lamp including install is $50. Program covers 70% of customer's project cost ($35 incentive value, or $0.20 per kWh). Expected gross annual participation is 4,000 lamps.

- Reconciling, tracking and reporting at 4 hours/week for 52 weeks
- Contractor also gets $0.05/kWh fee for delivery

COMM_T8: Commercial Super T8 lamp retrofit direct install, replacing standard T8 lamp. Average cost per lamp including install is $14. Program covers 79% of the customer's project cost ($11 per lamp incentive value, or $0.52/kWh). Expected gross annual participation is 3,500 lamps. The incentive rate per kWh is higher for this measure because the incentive share of lamp replacement cost is higher than for other commercial lamp measures, while the unit savings are significantly lower due to the assumption of a standard T8 baseline.

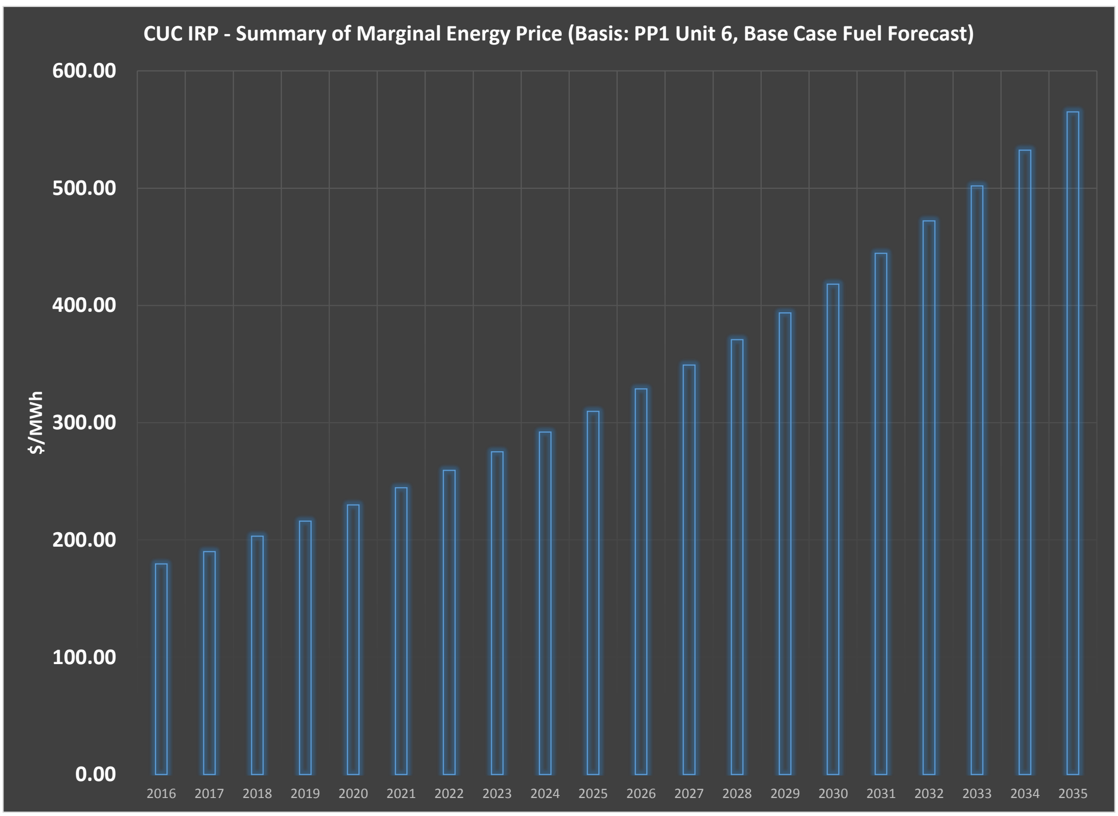
- Assumed 3.5 hours/week tracking and reporting for 52 weeks
- Contractor gets 5 cents/kWh delivery fee

COMM_REFRIG: Commercial refrigeration retrofit direct install, replacing various standard refrigeration measures. Value of the whole package including installation is

$1,100. Program covers 75% ($825) of customer's project cost. Expected annual participation is 35 packages.

- Because participation is assumed to be low quantity, assume tracking, reporting and contractor document reconciliation will be about 1 hour a week for 52 weeks
- $100,000 in Year 1 consulting support for marketing and outreach/implementation

With respect to avoided costs, the figure below summarizes the marginal energy rate that will be used in the screening of each of the DSM options defined above. The marginal energy rate is based on the assumption that every kWh abated contributes to the avoidance of CUC's least efficient resource (or the resource with the worst heat rate), and assumes the Base Case Fuel forecast as summarized elsewhere in this Assumptions Document. It is assumed that there are no avoided capacity or deferrals of infrastructure costs that will result from the portfolio of measures above given the impending need to procure new supply-side resources, and consequently, all savings attributable to DSM at the onset of the program are energy/fuel related.



It should be noted that as the DSM portfolio matures, it is likely that there may be significant momentum and uptake that would allow CUC to avoid future capacity additions, and such a condition should be monitored by CUC on a recurring basis as a part of prudent utility planning. Furthermore, the marginal energy rate above may flex as a function of an iterative process aimed at understanding the best course of action related to supply-side assets (via the screening and PROMOD analysis), which may result in an "alternative marginal asset" as the Study Period extends into a time wherein CUC has retired existing assets and added new assets. Leidos will revisit the findings of the DSM screening to determine if the benefit-cost analyses are robust to such changes prior to a measure being suggested for CUC endorsement as part of the final IRP report.

Renewable Portfolio Standard (RPS) Requirements

The RPS outlined in Public Law 15-23 which was signed into law in August of 2006 called for fairly aggressive renewable energy targets beginning in 2007 and culminating in 50% of net electricity sales coming from renewable sources by 2030.

One year later, in September of 2007, Public Law 15-23 was amended with the passing of Public Law 15-87. The amended RPS was significantly increased to require 80% of electricity sales from renewable sources by December 31, 2014. Renewable energy targets from both laws have not been achieved.

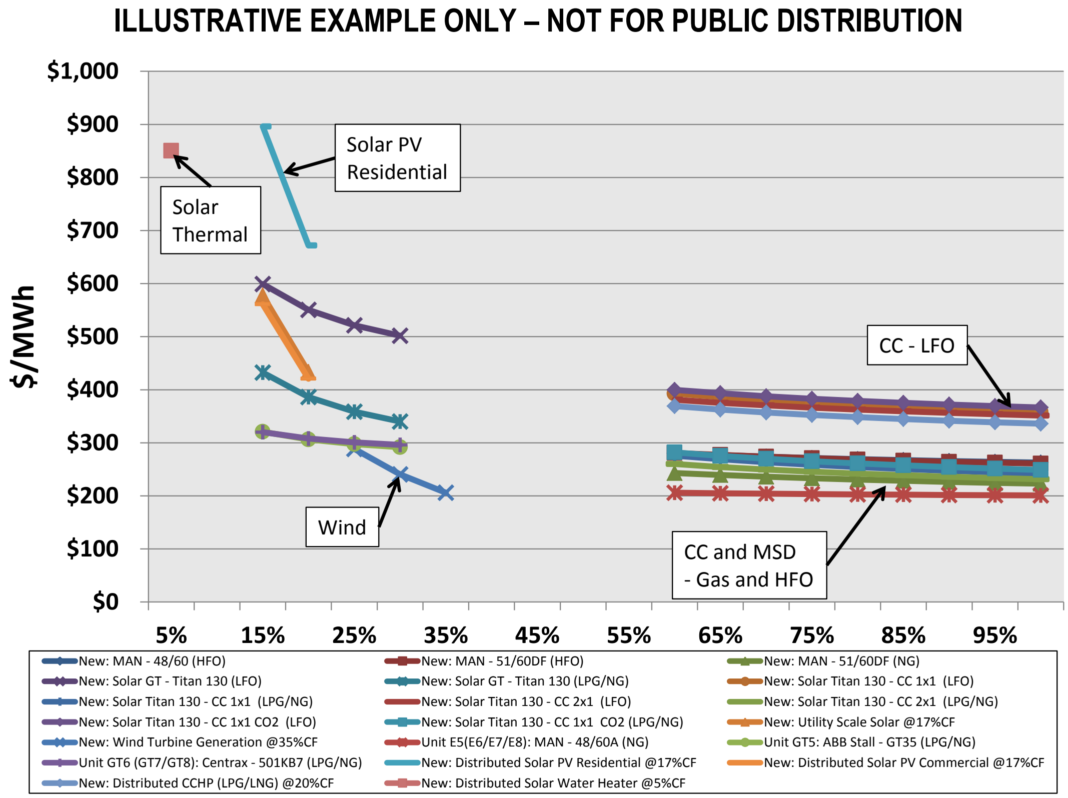
Public Law 18-62 was subsequently passed in January of 2014 and revised the renewable energy targets once more. The current RPS target is now 20% of CUC net electricity sales by December 31, 2016. PL 18-62 is silent on the RPS requirement beyond 2016. Therefore, a maximum RPS of 20% (which will not necessarily be prescriptive and is in part dependent upon the nature and extent of bids received) is assumed for compliance within the study period, with the understanding that higher levels of renewable energy could be possible if justified economically. It is assumed that compliance will be met by aggregating renewable energy across the three CUC systems.

Resource Screening

In advance of detailed modeling in PROMOD, Leidos will prepare a resource screening for each of the bids received during the ongoing RFP/Procurement, as well as the LNG scenario as defined by Leidos as described above. The resource screening will be conducted using Leidos' internal screening tool. The screening tool compiles capital, operating (fixed and variable), fuel, and other costs (if any) for each of the resource options (including renewable and DSM options), and then estimates the all-in $/MWh cost of each resource for a range of plausible capacity factors.

The purpose of the resource screening is to (i) provide a platform for review and quality control of all of the input assumptions for each potential future resource option, (ii) serve as a basis for potential follow-up with bidders, and (iii) provide an indication of the range of estimated power supply costs that can be expected for a given option, which will allow for the filtering of prohibitively expensive options from the downstream modeling. The more bounded the set of resource options with regard to the PROMOD modeling, the more time can be spent on valuable scenarios and review of results as compared to spending computing time evaluating portfolios that are clearly not economical or have some other fatal flaw (e.g. incomplete data).

The figure below provides an illustrative example of the results that can be anticipated from the resource screening.



Production Cost Modeling Scenario Definitions

The following is a bullet list of the main production cost modeling scenarios that will be contemplated as part of the IRP. Only resources that are deemed worthy of inclusion into this phase of the analysis subsequent to the resource screening (as described above) will be modeled within PROMOD. As the nature and extent of bids for new generating options is defined as the combination of the bids received, the LNG solution as estimated by Leidos, and the DSM measures suggested in the DSM Portfolio Definition subsection above, the scenarios posited herein are predicated upon that domain of options. Leidos has also prepared a scenario matrix (Appendix E of this document) that captures a suggested sequence of steps and combinations of PROMOD cases that are designed to capture the intent of the case descriptions below in a methodical manner that balances required computational time with the objectives of the simulations.

- **Business As Usual (BAU) Case** - this case serves as the basis for all other comparisons of production cost differentials, and assumes that CUC extends the life of the existing asset base through the end of the IRP study period, with associated costs to manufacture parts and engage in other necessary maintenance added to the core operational cost of the existing asset base.

- **Replacement Case** –this case assumes that (i) CUC will retire their existing asset fleet as predicated upon the agreed upon retirement order in Appendix B (which may flex depending upon the lead times associated with bids for alternative resources), (ii) CUC *will only procure replacement assets that are of the same fuel type at the same sites where existing native generation are located*, and that (ii) given such restrictions, CUC will choose the replacement assets that minimize the expected net present value (NPV) of production costs over the IRP Study Period. Multiple bids have been received associated with new diesel units, which will form the basis of the optionality around the Replacement case.
- **No. 6 Fuel Oil Case** – this case assumes that CUC will retire the existing units and rely upon the bid received related to No. 6 Fuel oil to serve anticipated future grid load. The environmental compliance costs associated with the No. 6 fuel oil bid were not included in the bidder response related to this solution. Consequently, as noted above, Leidos will provide an estimate of the capital costs and other costs associated with environmental compliance for this fuel as an adder to the core bidder costs associated with this case.
- **RPS/DSM Compliance Case** – this case assumes BAU capacity expansion coupled with the appropriate level of RPS/DSM compliance, as described above.
- **Alternative Case(s)** – this case will reflect the addition of any and all resource options made available to CUC, including options that involve new fuel infrastructure, renewable resources, and DSM (if appropriate). Leidos will work with CUC to devise the configuration or configurations for this case that may result in an expected net present value (NPV) of production costs that is lower than the BAU or compliance cases. Additionally, the Alternative Case may also serve as a basis for quantifying the cost differential associated with a more diversified portfolio of resources (which may include one or more bids modeled in tandem) as compared to the purely “least cost” case. Leidos will work with CUC to appropriately distinguish between assumptions prepared at a high-level for bids that were not received and assumptions derived directly from the procurement process.
- **Case Levers** – the following are case levers:
  - High Tourism/Load
  - Low Tourism/Load
  - High Rooftop PV Penetration (Lower Load)
  - Fuel Scenarios
  - Carbon Monetization (may not be necessary)
  - Delayed Retirement (of existing assets) (may not be necessary)

Introduction

The purpose of this document is to articulate the overarching strategy for completion of the CUC Integrated Resource Plan ("IRP"). This document has been informed by the full extent of interaction with CUC relative to Leidos' originally proposed scope of services, including our time spent on-island and our detailed discussions with both internal and external stakeholders.

This document is a companion to the detailed CUC Assumptions Document, which warehouses and codifies specific technical information regarding CUC's existing system, resource options, fuel projections, and modeling scenarios. The key distinction between the IRP Strategy Document and the IRP Assumptions Document is that the strategy document describes the guiding principles that drive how the IRP process will unfold at the strategic level without focusing on specific technical inputs that will be derived from executing the IRP strategy. Additionally, while the IRP Assumptions Document is intended to be a "working file" that evolves as data is gathered, the IRP Strategy Document defines the full boundary of activities that define the strategy and will be adhered to once complete in order to ensure that the strategy can be successfully executed[21]. Consensus regarding both documents is critical to the ultimate success and defensibility of the IRP.

Why do We Need an IRP Strategy?

At its core, the CUC IRP must truly strive to be "integrated" and provide *a holistic evaluation of supply-side and demand-side power delivery and demand abatement resource options for the utility over a long-term planning horizon, while balancing the benefits of such options with recognition of constraints, most notably cost, commercialization of technologies and associated risks, and the priorities of CUC's customers*. In fact, this core objective provides the broadest definition of a modern IRP. The IRP Strategy must steer all IRP related tasks and activities towards this goal. Additionally, the IRP Strategy can serve as a platform for strategic communication regarding the planning activities being undertaken to external parties, without undue focus on technical information that obfuscates the process relative to the priorities of a given audience.

CUC IRP Strategy

The IRP is fundamentally focused on answering two core questions, namely:

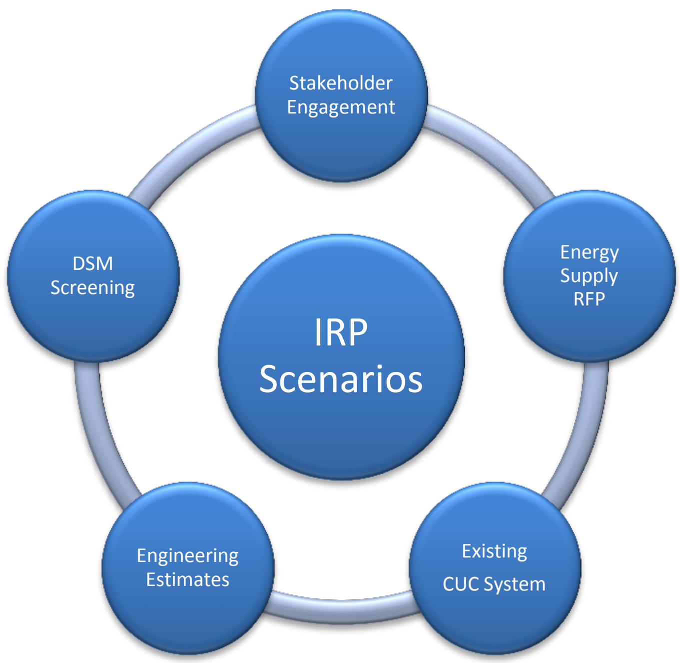
(i) What is the domain of plausible resource scenarios ("IRP Scenarios") that are actually available to CUC over a long term planning horizon?

[21] The IRP Strategy may be revisited during future IRP updates as deemed appropriate by CUC.

(ii) What are the analytical steps that must be taken to objectively evaluate these IRP Scenarios to arrive at a holistic plan to meet CUC's long term resource needs ("IRP Results")?

The IRP Strategy focuses on the interdependencies and areas of analysis required to develop defensible IRP Scenarios and analyze such scenarios to provide defensible IRP Results.

The figures below define the overarching CUC IRP Strategy. The first figure articulates the strategy for development of the IRP Scenarios, the guiding principles for which are explained further below.



IRP Scenarios – Guiding Principles

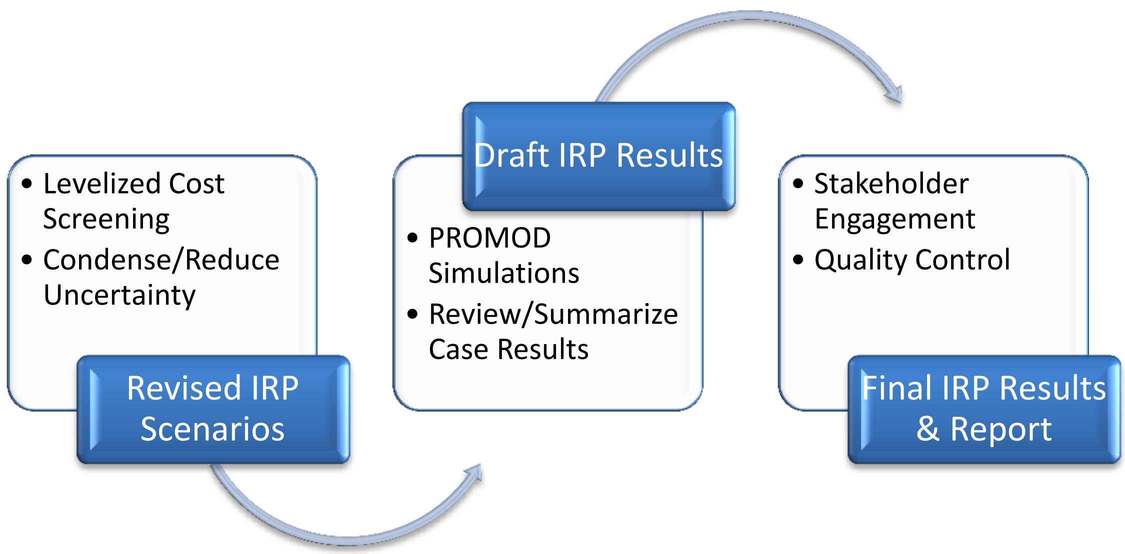
Each of the 5 rings around the core IRP Scenarios ring in the figure above represents an interdependent area of analysis that must be thoughtfully executed in order to understand the IRP Scenarios that are actually available to CUC (which drives their ultimate definition). As noted above, such analyses must adequately combine supply-side and demand-side resource options and balance benefits with costs and risks. The following guiding principles define the strategy in each area:

- ***Stakeholder engagement*** at strategic periods in the IRP ensures understanding (and not necessarily complete agreement) regarding the overarching IRP approach and the objectives of the planning activities. As part of such engagement, strategic communication to external parties using multiple mediums, including content on the CUC website, is critical to building trust with regard to the purpose and motivations behind the IRP.

- ***A detailed Energy Supply RFP process*** is essential to the availability of real-world input assumptions for power supply resources that are predicated on actual vendor bids; this is especially critical for the island communities of Saipan, Tinian, and Rota given their remote location and the challenges that poses with respect to development of "generic" resource assumptions for new construction and/or conservation and demand-side management (DSM) programs. While a traditional mainland IRP can be conducted absent a procurement process given the ability to reasonably estimate delivered power costs for new assets, and RFPs typically follow from the IRP results, it is critical to infuse the RFP process into the middle portion of the IRP in order to provide usable input assumptions to the analysis of CUC's resource options. Furthermore, a comprehensive evaluation of the viability of each vendor/bidder that participates in the RFP with respect to creditworthiness, prior work performance, and completeness of technical information provided will serve as a filter for incomplete or technically inferior proposals that will not be qualified for further evaluation within the IRP.
- ***CUC's Existing System*** must be fully understood, which involves a comprehensive effort to parameterize existing CUC power assets in terms of cost and performance, anticipated retirement schedules, and ongoing or impending major maintenance as well as to estimate, within reason, the cost to CUC (and their customers) of continuing to operate utility assets as has been done do date (or "business as usual" conditions); the defensibility of any course of action resulting from the IRP will hinge on the ultimate benefits to CUC and their customers relative to the costs and risks of maintaining "business as usual". Furthermore and equally as important, a detailed analysis of existing and future load growth/contraction and capacity requirements is critical to framing up a realistic amount of potential capacity expansion and/or DSM programs to serve such requirements. Finally, the cost of delivered fuel to serve not only CUC's current assets but potential new assets must be projected based on actual cash outlays and CUC's own insights regarding how fuel is currently delivered to the island. With respect to fuel and load futures, a range of plausible forecasts must be considered in concert with the other interdependent areas of analysis in order to properly characterize the risks of a particular power supply (or demand abatement) portfolio.
- ***Engineering Estimates*** will be required to supplement assumptions gathered during the RFP process for commercially viable technologies that may not be found in the domain of responses to the RFP. These estimates must be as representative as possible in order to avoid exclusion of viable options as a function of a specific iteration of procurement. Importantly, technologies determined to be not commercially viable will be excluded from such estimates.
- ***A DSM screening*** will be required for the same reason as the Engineering Estimates above, but with respect to the DSM landscape, which must include a realistic and carefully bounded evaluation of "low hanging fruit" measures (which can include conservation, demand response, and energy efficiency options). Carefully designed programs in this realm can potentially reduce load to be served by traditional grid resources in a cost-effective manner while also avoiding certain

environmental externalities associated with traditional fossil fuel resources. However, the capacity of CUC to administer these programs and a realistic evaluation of program potential should serve as balancing constraints that control the influence of DSM on the IRP Scenarios and IRP Results.

The second figure articulates the strategy for transforming the IRP Scenarios developed via the interdependent activities defined above into the final IRP Results and final IRP Report.



IRP Results – Guiding Principles

As evidenced by the figure above, the guiding principles that will define the strategy to produce the IRP Results are as follows:

- ***A levelized cost screening*** will be conducted on both the data received during the RFP process and the engineering/DSM options. The purpose of the screening will be to provide a layer of quality control on the input assumptions underpinning each viable option. Additionally, it is anticipated that the levelized cost screening ***will condense the optionality within certain RFP responses and reduce the uncertainty associated with downstream simulations*** in order to control the number of possible outcomes and reduce the simulations to only those that appear economically attractive as a result of the screening process. While each option will ultimately be simulated within PROMOD, it is likely that sub-options within a given bid can be eliminated either due to prohibitively high expense, grid constraints, or other qualitatively derived areas of risk that render more detailed simulations unnecessary. Detailed follow-up with qualified RFP respondents will be conducted in order to ensure that the best available information is considered in the ultimate IRP evaluation.

- ***Revised IRP Scenarios*** will result from the levelized cost process that will serve to narrow down the wider universe of potential scenarios into those that are economically attractive and which do not pose significant environmental, vendor, or other logistical risks. These scenarios will be arranged into a scenario matrix that will define how the PROMOD simulations will be undertaken. Careful forethought will be required in order to ensure that the various bids and engineering/DSM estimated options are considered in the right combinations and with sufficient rigor to ensure that the best available long term asset deployment strategy can be extracted from the universe of plausible IRP scenarios.
- ***PROMOD simulations*** will be run on the revised scenarios and will be subjected to review and extraction of results in a format conducive to further evaluation. Importantly, various scenarios will be compared against each other as well as against CUC's "business as usual".
- ***Draft IRP Results*** will be subjected to an additional iteration of ***stakeholder feedback and quality control*** prior to the submission of the ***final IRP Report***.

Risk Mitigation Tactics for Avoiding Undesirable IRP Outcomes

Over the course of any long range IRP, there are inevitably certain risks that can result in undesirable project outcomes. Having foresight with regard to such risks and ensuring that adequate risk mitigation tactics are in place to manage those risks is an often-overlooked and critical component of the IRP Strategy. The matrix below summarizes the key undesired outcomes identified for the CUC IRP, and the mitigation tactics embedded in the IRP Strategy that are intended to minimize the likelihood of such outcomes.

Risk/Undesired Outcome	Mitigation Tactic(s)
CUC does not receive any viable bids resulting from the Procurement/RFP.	• Perform vendor outreach at strategic times prior to RFP issuance. • Conduct pre-RFP webinar to explain purpose and boundaries around RFP. • Conduct Question & Answer session regarding procurement questions to encourage maximum participation. • Limit the constraints or restrictions around the proposed solution to encourage a diverse menu of bids.
Parties External to CUC do not properly understand what the IRP is intending to achieve, and the IRP's credibility is questioned.	• Conduct stakeholder engagement at the early stages of the IRP, including interviews with both internal and external staff. • Meta-analyze stakeholder feedback to uncover the key priorities internal to CUC as well as with respect to CUC's customer base.

Risk/Undesired Outcome	Mitigation Tactic(s)
	• Develop strategic communications regarding the IRP on CUC's website and through other media sources. • Ensure further interaction with stakeholders as IRP results are being assembled to avoid "surprises" with regard to the implications.
Bidders in the Procurement/RFP process challenge or otherwise object to the RFP review process.	• Assign diverse evaluation panel comprised of both Leidos and CUC staff. • Design rigorous and detailed evaluation criteria and document each evaluation member's score via an electronic model. • Require evaluation committee members to sign Attestation Statements certifying the integrity of the evaluation process.
CUC does not have adequate data to support a proper characterization of their existing system (or "business as usual") costs, rendering comparisons to other IRP Scenarios indefensible.	• Develop dedicated Assumptions Document to codify each and every input assumption related to CUC's operating costs. • Require back-up documentation for key input assumptions that materially impact CUC costs. • Partner with CUC's rate consultant to review and obtain the best data possible. • Ground-truth input assumptions with engineering expertise and review of CUC's accounting to better compartmentalize costs. • Perform test runs of CUC's base case operations prior to onset of detailed production cost modeling.
There are an inordinate number of combinations of IRP Scenarios relative to constraints around production cost simulations.	• Perform levelized cost of energy screening on each individual asset or option to deterministically compare bids/options in a less-time intensive fashion. • Reduce the uncertainty and optionality of the process by working to winnow down multiple bids/options to only those that are economically attractive for modeling within PROMOD.

Risk/Undesired Outcome	Mitigation Tactic(s)
	• Define scenarios in Assumptions Document and work to codify them with CUC in a manner that avoids duplication. • Limit sub-scenarios to those factors that are most likely to drive future uncertainty for CUC.
The IRP is conducted "in a vacuum" and indications regarding results are not known until the process has ended.	• Leverage levelized cost of energy screening results to provide initial indications regarding potential outcomes/IRP Results. • Update Assumptions Document as data is compiled. • Hold regular IRP team calls with CUC to track progress, obtain feedback, and ensure that any significant challenges are communicated proactively.
The disaster resiliency of an island system relative to certain resource options is sub-optimal.	• Include qualitative and logistical review of resource options to evaluate ability of procurement process assets to withstand storm damage. • Include site considerations as part of procurement evaluation process. • Consider siting issues when developing engineering estimates.

Table C-1
CUC System Cost Summary for Case 1: Business-as-Usual

		Levelized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NET SALES	GWH	**219.8**	**218.0**	**218.9**	**219.9**	**220.2**	**219.2**	**219.2**	**219.4**	**219.4**	**219.4**	**219.5**	**219.5**	**219.5**	**219.5**
AMORTIZED CAPITAL COSTS															
Capacity Charge - Generation	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS															
Fuel - Existing	$000	90,972	45,824	48,616	52,255	55,574	59,206	62,966	66,929	70,946	75,447	79,937	84,986	90,383	96,064
Fuel - New	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M - Existing	$000	7,335	4,585	4,804	5,055	5,271	5,486	5,715	5,967	6,248	6,542	6,776	7,112	7,393	7,748
Variable O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M - Existing	$000	3,773	2,637	2,729	2,825	2,924	3,026	3,133	3,242	3,356	3,474	3,596	3,722	3,853	3,988
Fixed O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL COSTS	**$000**	**74,674**	**53,046**	**56,150**	**60,135**	**63,769**	**67,719**	**71,814**	**76,138**	**80,550**	**85,462**	**90,309**	**95,819**	**101,629**	**107,800**
	$/MWh	**339.8**	**243.4**	**256.5**	**273.4**	**289.6**	**309.0**	**327.6**	**347.1**	**367.1**	**389.5**	**411.5**	**436.6**	**463.0**	**491.1**

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NET SALES	GWH	**219.5**	**219.4**	**219.5**	**219.5**	**219.4**	**222.1**	**222.0**	**221.9**	**221.9**	**221.8**	**221.8**	**221.6**
AMORTIZED CAPITAL COSTS													
Capacity Charge - Generation	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS													
Fuel - Existing	$000	102,022	108,273	115,415	122,667	130,478	139,899	148,635	157,771	167,635	178,455	190,102	200,961
Fuel - New	$000	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M - Existing	$000	8,094	8,442	8,809	9,233	9,662	10,222	10,711	11,123	11,668	12,219	12,766	13,318
Variable O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M - Existing	$000	4,128	4,274	4,424	4,579	4,741	4,907	5,080	5,259	5,444	5,636	5,835	6,040
Fixed O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	$000	-	-	-	-	-	-	-	-	-	-	-	-
DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL COSTS	**$000**	**114,245**	**120,988**	**128,648**	**136,480**	**144,881**	**155,028**	**164,427**	**174,153**	**184,747**	**196,310**	**208,703**	**220,319**
	$/MWh	**520.6**	**551.3**	**586.1**	**621.9**	**660.4**	**698.1**	**740.6**	**784.8**	**832.7**	**885.1**	**941.1**	**994.1**

Table C-2
CUC System Capacity Summary for Case 1: Business-as-Usual

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPACITY														
Existing Thermal	MW	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
New Thermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	MW	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL CAPACITY		98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
PEAK DEMAND	MW	42.9	43.3	43.5	43.6	43.5	43.6	43.7	43.7	43.6	43.8	43.8	43.8	43.7
DSM	MW	-	-	-	-	-	-	-	-	-	-	-	-	-
NEM	MW	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Peak (net of DSM/NEM)	MW	42.9	43.2	43.4	43.5	43.3	43.4	43.4	43.4	43.3	43.5	43.5	43.5	43.4
Reserve Requirements	MW	42.9	43.2	43.4	43.5	43.3	43.4	43.4	43.4	43.3	43.5	43.5	43.5	43.4
Total Capacity Requirements	MW	85.9	86.5	86.9	87.0	86.5	86.8	86.9	86.9	86.7	86.9	87.0	87.0	86.8
Surplus/(Deficiency)	MW	12.8	12.2	11.8	11.7	12.2	11.9	11.8	11.8	12.0	11.8	11.7	11.7	11.9

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CAPACITY													
Existing Thermal	MW	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
New Thermal	MW	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	MW	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL CAPACITY		98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
PEAK DEMAND	MW	43.9	43.9	43.9	43.8	43.9	44.3	44.3	44.2	44.4	44.4	44.4	44.3
DSM	MW	-	-	-	-	-	-	-	-	-	-	-	-
NEM	MW	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6
Peak (net of DSM/NEM)	MW	43.5	43.5	43.5	43.4	43.5	43.9	43.9	43.8	43.9	43.9	43.9	43.7
Reserve Requirements	MW	43.5	43.5	43.5	43.4	43.5	43.9	43.9	43.8	43.9	43.9	43.9	43.7
Total Capacity Requirements	MW	87.0	87.0	87.0	86.8	87.0	87.8	87.8	87.5	87.8	87.7	87.7	87.5
Surplus/(Deficiency)	MW	11.7	11.7	11.7	11.9	11.7	10.9	10.9	11.2	10.9	11.0	11.0	11.2

Table C-3a
CUC System Operations Summary for Case 1: Business-as-Usual

CUC TOTAL		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
GENERATION														
Existing Thermal	GWH	260.9	262.1	263.1	263.4	262.6	262.6	262.7	262.7	262.9	262.9	262.9	263.0	263.0
New Thermal	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL GENERATION		260.9	262.1	263.1	263.4	262.6	262.6	262.7	262.7	262.9	262.9	262.9	263.0	263.0
Excess Generation	GWH	(0.3)	(0.3)	(0.1)	(0.1)	(0.2)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	-	(0.0)	(0.0)
Emergency Energy	GWH	0.0	0.0	-	-	0.0	0.0	-	0.0	-	0.0	0.0	0.0	0.0
System Load	GWH	260.7	261.9	263.2	263.9	264.1	264.3	264.6	264.8	264.9	265.1	265.3	265.4	265.6
DSM	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-
NEM	GWH	0.0	0.1	0.2	0.5	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.5	2.6
Losses	GWH	42.7	42.9	43.1	43.2	43.3	43.3	43.3	43.4	43.4	43.4	43.4	43.5	43.5
Net Sales (excl losses)	GWH	218.0	218.9	219.9	220.2	219.2	219.2	219.4	219.4	219.4	219.5	219.5	219.5	219.5
LOLH	HOURS	7	20	-	-	20	9	-	20	-	3	16	1	4
FUEL														
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	431	432	434	433	433	433	433	433	433	433	433	433	434
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS														
Energy from Renewables	%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%
CO_2	TONS (000)	200	201	201	201	201	201	201	201	201	201	201	201	201
CO_2 Intensity	LBS/MWH	1,836	1,833	1,832	1,828	1,836	1,834	1,835	1,833	1,835	1,831	1,832	1,833	1,835
NO_X	TONS (000)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0

Table C-3b
CUC System Operations Summary for Case 1: Business-as-Usual

CUC TOTAL		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
GENERATION													
Existing Thermal	GWH	263.0	263.0	263.0	263.0	263.0	266.2	266.2	266.1	266.1	265.9	266.0	265.9
New Thermal	GWH	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	GWH	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL GENERATION		263.0	263.0	263.0	263.0	263.0	266.2	266.2	266.1	266.1	265.9	266.0	265.9
Excess Generation	GWH	-	(0.0)	(0.0)	(0.0)	-	-	-	(0.0)	-	-	-	(0.0)
Emergency Energy	GWH	0.0	-	0.0	0.0	0.1	-	-	-	0.0	0.1	-	0.0
System Load	GWH	265.7	265.8	266.0	266.1	266.2	269.6	269.7	269.8	269.9	270.0	270.2	270.2
DSM	GWH	-	-	-	-	-	-	-	-	-	-	-	-
NEM	GWH	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	3.8	4.0	4.2	4.3
Losses	GWH	43.5	43.5	43.6	43.6	43.6	44.1	44.2	44.2	44.2	44.2	44.2	44.3
Net Sales (excl losses)	GWH	219.5	219.4	219.5	219.5	219.4	222.1	222.0	221.9	221.9	221.8	221.8	221.6
LOLH	HOURS	15	-	61	4	28	-	-	-	3	52	-	31
FUEL													
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	433	433	434	433	433	438	438	438	438	438	438	438
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS													
Energy from Renewables	%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%
CO_2	TONS (000)	201	201	201	201	201	204	181	180	180	180	180	180
CO_2 Intensity	LBS/MWH	1,834	1,832	1,835	1,835	1,835	1,834	1,634	1,623	1,622	1,624	1,623	1,624
NO_X	TONS (000)	3.0	3.0	3.0	3.0	3.0	3.0	2.7	2.7	2.7	2.7	2.7	2.7

Table C-4
CUC System Cost Summary for Case 9: BAU with 10MW PV

		Levelized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NET SALES	GWH	**219.8**	**218.0**	**218.9**	**219.9**	**220.2**	**219.2**	**219.2**	**219.4**	**219.4**	**219.4**	**219.5**	**219.5**	**219.5**	**219.5**
AMORTIZED CAPITAL COSTS															
Capacity Charge - Generation	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS															
Fuel - Existing	$000	83,056	45,701	48,384	51,160	51,179	54,238	57,610	61,016	64,582	68,551	72,352	76,773	81,511	86,424
Fuel - New	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M - Existing	$000	6,753	4,566	4,770	4,936	4,873	5,067	5,264	5,492	5,723	5,957	6,200	6,497	6,732	7,018
Variable O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M - Existing	$000	3,773	2,637	2,729	2,825	2,924	3,026	3,133	3,242	3,356	3,474	3,596	3,722	3,853	3,988
Fixed O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	$000	2,584	-	-	610	3,090	3,105	3,103	3,112	3,120	3,136	3,135	3,142	3,149	3,167
DSM	$000	371	607	312	322	333	344	355	367	379	391	404	418	431	446
TOTAL COSTS	**$000**	**72,131**	**53,511**	**56,195**	**59,853**	**62,398**	**65,781**	**69,465**	**73,230**	**77,160**	**81,509**	**85,687**	**90,551**	**95,676**	**101,042**
	$/MWh	**328.2**	**245.5**	**256.7**	**272.2**	**283.4**	**300.1**	**316.8**	**333.8**	**351.7**	**371.5**	**390.4**	**412.6**	**435.9**	**460.3**

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NET SALES	GWH	**219.5**	**219.4**	**219.5**	**219.5**	**219.4**	**222.1**	**222.0**	**221.9**	**221.9**	**221.8**	**221.8**	**221.6**
AMORTIZED CAPITAL COSTS													
Capacity Charge - Generation	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - T & D	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS													
Fuel - Existing	$000	91,542	96,947	103,180	109,762	116,746	125,351	133,330	141,969	151,353	161,890	173,057	183,365
Fuel - New	$000	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M - Existing	$000	7,333	7,613	7,929	8,299	8,700	9,238	9,660	10,096	10,632	11,114	11,685	12,216
Variable O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M - Existing	$000	4,128	4,274	4,424	4,579	4,741	4,907	5,080	5,259	5,444	5,636	5,835	6,040
Fixed O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	$000	3,166	3,173	3,181	3,196	3,196	3,204	3,212	3,228	3,227	3,234	3,242	3,260
DSM	$000	460	476	491	507	524	542	559	-	-	-	-	-
TOTAL COSTS	**$000**	**106,630**	**112,482**	**119,205**	**126,343**	**133,906**	**143,242**	**151,841**	**160,552**	**170,656**	**181,873**	**193,820**	**204,882**
	$/MWh	**485.9**	**512.6**	**543.1**	**575.7**	**610.4**	**645.1**	**684.0**	**723.5**	**769.2**	**820.0**	**874.0**	**924.4**

Table C-5
CUC System Capacity Summary for Case 9: BAU with 10MW PV

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPACITY														
Existing Thermal	MW	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
New Thermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	MW	-	-	-	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.3
TOTAL CAPACITY		98.7	98.7	98.7	101.2	101.2	101.2	101.1	101.1	101.1	101.1	101.1	101.1	101.0
PEAK DEMAND	MW	42.9	43.3	43.5	43.6	43.5	43.6	43.7	43.7	43.6	43.8	43.8	43.8	43.7
DSM	MW	0.3	0.5	0.8	1.1	1.3	1.6	1.9	2.1	2.3	2.5	2.7	2.9	3.1
NEM	MW	0.0	-	-	-	-	-	-	-	-	-	-	-	-
Peak (net of DSM/NEM)	MW	42.7	42.7	42.7	42.5	42.2	42.1	41.8	41.6	41.3	41.3	41.1	40.9	40.6
Reserve Requirements	MW	42.7	42.7	42.7	42.5	42.2	42.1	41.8	41.6	41.3	41.3	41.1	40.9	40.6
Total Capacity Requirements	MW	85.3	85.5	85.3	85.0	84.3	84.1	83.6	83.2	82.6	82.5	82.2	81.9	81.3
Surplus/(Deficiency)	MW	13.4	13.2	13.4	16.2	16.9	17.1	17.5	18.0	18.5	18.6	18.9	19.2	19.7

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CAPACITY													
Existing Thermal	MW	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
New Thermal	MW	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	MW	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.1
TOTAL CAPACITY		101.0	101.0	101.0	101.0	101.0	100.9	100.9	100.9	100.9	100.9	100.9	100.8
PEAK DEMAND	MW	43.9	43.9	43.9	43.8	43.9	44.3	44.3	44.2	44.4	44.4	44.4	44.3
DSM	MW	3.3	3.5	3.6	3.6	3.6	3.6	3.6	3.3	3.1	2.8	2.5	2.3
NEM	MW	-	-	-	-	-	-	-	-	-	-	-	-
Peak (net of DSM/NEM)	MW	40.6	40.4	40.3	40.2	40.3	40.7	40.7	40.9	41.3	41.6	41.9	42.0
Reserve Requirements	MW	40.6	40.4	40.3	40.2	40.3	40.7	40.7	40.9	41.3	41.6	41.9	42.0
Total Capacity Requirements	MW	81.2	80.9	80.6	80.4	80.7	81.4	81.5	81.8	82.6	83.2	83.8	84.1
Surplus/(Deficiency)	MW	19.8	20.2	20.4	20.6	20.3	19.5	19.4	19.1	18.3	17.7	17.1	16.7

Table C-6a
CUC System Operations Summary for Case 9: BAU with 10MW PV

CUC TOTAL		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
GENERATION														
Existing Thermal	GWH	260.1	260.5	256.9	241.1	239.5	239.0	238.4	237.8	237.3	236.8	236.3	235.8	235.1
New Thermal	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	GWH	-	-	3.8	19.1	19.0	18.8	18.7	18.5	18.5	18.3	18.1	18.0	17.9
TOTAL GENERATION		260.1	260.5	260.7	260.2	258.6	257.8	257.1	256.3	255.7	255.1	254.4	253.7	253.0
Excess Generation	GWH	(0.3)	(0.3)	(0.1)	(0.1)	(0.2)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	-	(0.0)	(0.0)
Emergency Energy	GWH	0.0	0.0	-	-	0.0	0.0	-	0.0	-	0.0	0.0	0.0	0.0
System Load	GWH	260.7	261.9	263.2	263.9	264.1	264.3	264.6	264.8	264.9	265.1	265.3	265.4	265.6
DSM	GWH	0.8	1.6	2.4	3.2	4.0	4.8	5.6	6.4	7.2	7.8	8.5	9.2	10.0
NEM	GWH	0.0	0.1	0.2	0.5	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.5	2.6
Losses	GWH	42.7	42.9	43.1	43.2	43.3	43.3	43.3	43.4	43.4	43.4	43.4	43.5	43.5
Net Sales (excl losses)	GWH	217.2	217.3	217.5	217.0	215.1	214.4	213.8	213.0	212.3	211.6	210.9	210.3	209.5
LOLH	HOURS	6	20	-	-	6	9	-	7	-	3	13	1	3
FUEL														
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	430	430	424	398	396	395	394	393	393	391	390	390	389
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS														
Energy from Renewables	%	0%	0%	2%	9%	10%	10%	10%	10%	10%	10%	10%	10%	10%
CO_2	TONS (000)	200	200	197	185	184	184	183	183	182	181	181	181	181
CO_2 Intensity	LBS/MWH	1,831	1,824	1,792	1,680	1,678	1,674	1,669	1,665	1,663	1,654	1,651	1,650	1,647
NO_X	TONS (000)	2.9	2.9	2.9	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7

Table C-6b
CUC System Operations Summary for Case 9: BAU with 10MW PV

CUC TOTAL		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
GENERATION													
Existing Thermal	GWH	234.6	234.1	233.7	233.7	233.9	237.3	237.3	238.2	239.1	239.9	240.9	241.6
New Thermal	GWH	-	-	-	-	-	-	-	-	-	-	-	-
New Renewables	GWH	17.7	17.6	17.5	17.4	17.2	17.1	16.9	16.9	16.7	16.6	16.4	16.4
TOTAL GENERATION		252.4	251.7	251.1	251.1	251.1	254.3	254.3	255.0	255.8	256.5	257.3	258.0
Excess Generation	GWH	-	(0.0)	(0.0)	(0.0)	-	-	-	(0.0)	-	-	-	(0.0)
Emergency Energy	GWH	0.0	-	0.0	0.0	0.0	-	-	-	0.0	0.0	-	0.0
System Load	GWH	265.7	265.8	266.0	266.1	266.2	269.6	269.7	269.8	269.9	270.0	270.2	270.2
DSM	GWH	10.7	11.4	11.9	11.9	11.9	11.9	11.9	11.1	10.3	9.5	8.7	7.9
NEM	GWH	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	3.8	4.0	4.2	4.3
Losses	GWH	43.5	43.5	43.6	43.6	43.6	44.1	44.2	44.2	44.2	44.2	44.2	44.3
Net Sales (excl losses)	GWH	208.8	208.1	207.6	207.5	207.5	210.2	210.1	210.8	211.6	212.3	213.1	213.7
LOLH	HOURS	15	-	61	4	20	-	-	-	3	22	-	26
FUEL													
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	388	387	387	387	387	392	393	393	395	397	398	399
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS													
Energy from Renewables	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	9%	9%
CO_2	TONS (000)	180	180	180	180	180	182	160	159	160	161	161	162
CO_2 Intensity	LBS/MWH	1,642	1,637	1,637	1,638	1,639	1,640	1,442	1,437	1,441	1,451	1,456	1,461
NO_x	TONS (000)	2.7	2.6	2.6	2.7	2.7	2.7	2.4	2.4	2.4	2.4	2.4	2.4

Table C-7
CUC System Cost Summary for Case 12: LFO with 10MW PV

		Levelized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NET SALES	GWH	**219.8**	**218.0**	**218.9**	**219.9**	**220.2**	**219.2**	**219.2**	**219.4**	**219.4**	**219.4**	**219.5**	**219.5**	**219.5**	**219.5**
AMORTIZED CAPITAL COSTS															
Capacity Charge - Generation	$000	5,670	2,460	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS															
Fuel - Existing	$000	18,856	30,821	9,885	10,669	10,835	11,634	12,136	12,674	13,971	14,363	15,024	16,197	17,188	18,537
Fuel - New	$000	59,602	14,009	35,801	37,670	37,497	39,595	42,236	44,827	47,018	50,190	53,240	56,306	59,663	62,974
Variable O&M - Existing	$000	2,113	3,218	1,350	1,416	1,449	1,519	1,564	1,622	1,724	1,767	1,835	1,925	2,008	2,107
Variable O&M - New	$000	6,301	1,979	4,947	5,057	4,910	5,045	5,248	5,449	5,586	5,834	6,051	6,259	6,472	6,674
Fixed O&M - Existing	$000	2,242	2,163	1,566	1,623	1,683	1,744	1,808	1,874	1,943	2,014	2,088	2,164	2,244	2,326
Fixed O&M - New	$000	4,869	1,458	3,589	3,718	3,852	3,990	4,134	4,283	4,437	4,597	4,762	4,934	5,111	5,295
Renewable	$000	2,584	-	-	610	3,090	3,105	3,103	3,112	3,120	3,136	3,135	3,142	3,149	3,167
DSM	$000	371	607	312	322	333	344	355	367	379	391	404	418	431	446
TOTAL COSTS	**$000**	**78,661**	**56,715**	**63,352**	**66,989**	**69,551**	**72,880**	**76,488**	**80,111**	**84,080**	**88,196**	**92,442**	**97,248**	**102,169**	**107,427**
	$/MWh	**357.9**	**260.2**	**289.4**	**304.6**	**315.9**	**332.5**	**348.9**	**365.2**	**383.2**	**401.9**	**421.2**	**443.1**	**465.4**	**489.4**

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NET SALES	GWH	**219.5**	**219.4**	**219.5**	**219.5**	**219.4**	**222.1**	**222.0**	**221.9**	**221.9**	**221.8**	**221.8**	**221.6**
AMORTIZED CAPITAL COSTS													
Capacity Charge - Generation	$000	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903	5,903
Debt Service - T & D	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS													
Fuel - Existing	$000	19,505	20,053	21,803	23,050	24,370	26,959	27,245	28,997	31,715	34,181	35,443	38,389
Fuel - New	$000	66,875	71,287	75,432	80,371	85,581	91,464	98,337	104,839	111,194	118,443	127,527	134,683
Variable O&M - Existing	$000	2,188	2,252	2,368	2,461	2,570	2,741	2,779	2,905	3,080	3,238	3,330	3,517
Variable O&M - New	$000	6,937	7,230	7,474	7,777	8,076	8,455	8,898	9,277	9,628	10,014	10,543	10,903
Fixed O&M - Existing	$000	2,411	2,500	2,591	2,686	2,785	2,887	2,993	3,103	3,218	3,336	3,459	3,586
Fixed O&M - New	$000	5,486	5,684	5,888	6,100	6,320	6,547	6,783	7,027	7,280	7,542	7,814	8,095
Renewable	$000	3,166	3,173	3,181	3,196	3,196	3,204	3,212	3,228	3,227	3,234	3,242	3,260
DSM	$000	460	476	491	507	524	542	559	-	-	-	-	-
TOTAL COSTS	**$000**	**112,931**	**118,557**	**125,131**	**132,052**	**139,325**	**148,702**	**156,710**	**165,279**	**175,244**	**185,891**	**197,261**	**208,335**
	$/MWh	**514.6**	**540.3**	**570.1**	**601.7**	**635.1**	**669.6**	**705.9**	**744.8**	**789.9**	**838.1**	**889.5**	**940.0**

Table C-8
CUC System Capacity Summary for Case 12: LFO with 10MW PV

CUC TOTAL		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPACITY														
Existing Thermal	MW	98.7	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2
New Thermal	MW	-	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4
New Renewables	MW	-	-	-	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.3
TOTAL CAPACITY		98.7	93.6	93.6	96.1	96.0	96.0	96.0	96.0	96.0	95.9	95.9	95.9	95.9
PEAK DEMAND	MW	42.9	43.3	43.5	43.6	43.5	43.6	43.7	43.7	43.6	43.8	43.8	43.8	43.7
DSM	MW	0.3	0.5	0.8	1.1	1.3	1.6	1.9	2.1	2.3	2.5	2.7	2.9	3.1
NEM	MW	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Peak (net of DSM/NEM)	MW	42.7	42.7	42.6	42.4	41.9	41.8	41.6	41.3	41.0	41.0	40.8	40.6	40.3
Reserve Requirements	MW	42.7	31.3	31.3	31.4	31.4	31.4	31.4	31.4	31.4	31.4	31.5	31.5	31.5
Total Capacity Requirements	MW	85.3	74.0	74.0	73.8	73.3	73.2	73.0	72.7	72.4	72.4	72.2	72.1	71.8
Surplus/(Deficiency)	MW	13.4	19.6	19.6	22.2	22.7	22.8	23.0	23.2	23.5	23.5	23.7	23.8	24.1

CUC TOTAL		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CAPACITY													
Existing Thermal	MW	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2
New Thermal	MW	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4
New Renewables	MW	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.1
TOTAL CAPACITY		95.9	95.9	95.8	95.8	95.8	95.8	95.8	95.8	95.7	95.7	95.7	95.7
PEAK DEMAND	MW	43.9	43.9	43.9	43.8	43.9	44.3	44.3	44.2	44.4	44.4	44.4	44.3
DSM	MW	3.3	3.5	3.6	3.6	3.6	3.6	3.6	3.3	3.1	2.8	2.5	2.3
NEM	MW	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6
Peak (net of DSM/NEM)	MW	40.2	40.1	39.9	39.8	39.9	40.3	40.3	40.4	40.8	41.1	41.3	41.5
Reserve Requirements	MW	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.6	31.6	31.6	31.6
Total Capacity Requirements	MW	71.7	71.5	71.4	71.3	71.4	71.8	71.8	72.0	72.4	72.6	72.9	73.0
Surplus/(Deficiency)	MW	24.1	24.3	24.4	24.5	24.4	24.0	24.0	23.8	23.4	23.1	22.8	22.7

Table C-9a
CUC System Operations Summary for Case 12: LFO with 10MW PV

CUC TOTAL		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
GENERATION														
Existing Thermal	GWH	170.6	43.8	44.2	42.4	42.7	41.9	41.5	43.2	41.8	41.6	42.1	42.2	42.9
New Thermal	GWH	89.6	216.6	212.7	198.7	196.8	197.2	196.9	194.6	195.4	195.2	194.2	193.5	192.3
New Renewables	GWH	-	-	3.8	19.1	19.0	18.8	18.7	18.5	18.5	18.3	18.1	18.0	17.9
TOTAL GENERATION		260.2	260.4	260.7	260.3	258.6	257.8	257.1	256.4	255.7	255.1	254.4	253.7	253.0
Excess Generation	GWH	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	-	-	(0.0)
Emergency Energy	GWH	-	0.0	-	-	-	0.0	-	-	-	0.0	-	0.0	0.0
System Load	GWH	260.7	261.9	263.2	263.9	264.1	264.3	264.6	264.8	264.9	265.1	265.3	265.4	265.6
DSM	GWH	0.8	1.6	2.4	3.2	4.0	4.8	5.6	6.4	7.2	7.8	8.5	9.2	10.0
NEM	GWH	0.0	0.1	0.2	0.5	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.5	2.6
Losses	GWH	42.7	42.9	43.1	43.2	43.3	43.3	43.3	43.4	43.4	43.4	43.4	43.5	43.5
Net Sales (excl losses)	GWH	217.2	217.3	217.5	217.0	215.1	214.4	213.8	213.0	212.3	211.6	210.9	210.3	209.5
LOLH	HOURS	-	27	-	-	-	9	-	-	-	6	-	10	8
FUEL														
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	421	405	400	375	373	372	371	371	369	368	368	367	367
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS														
Energy from Renewables	%	0%	0%	2%	9%	10%	10%	10%	10%	10%	10%	10%	10%	10%
CO_2	TONS (000)	196	188	186	174	173	173	172	172	172	171	171	170	170
CO_2 Intensity	LBS/MWH	1,795	1,720	1,691	1,584	1,583	1,578	1,571	1,570	1,564	1,558	1,557	1,553	1,552
NO_X	TONS (000)	2.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Table C-9b
CUC System Operations Summary for Case 12: LFO with 10MW PV

CUC TOTAL		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
GENERATION													
Existing Thermal	GWH	42.6	41.5	42.2	42.0	42.1	44.0	41.8	42.1	43.4	44.1	42.9	44.3
New Thermal	GWH	192.0	192.5	191.4	191.7	191.8	193.3	195.6	196.0	195.7	195.9	197.9	197.3
New Renewables	GWH	17.7	17.6	17.5	17.4	17.2	17.1	16.9	16.9	16.7	16.6	16.4	16.4
TOTAL GENERATION		252.3	251.7	251.1	251.1	251.1	254.3	254.3	255.0	255.8	256.5	257.3	258.0
Excess Generation	GWH	-	(0.0)	(0.0)	(0.0)	(0.0)	-	-	-	-	-	(0.0)	(0.0)
Emergency Energy	GWH	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0	-	0.0	0.0
System Load	GWH	265.7	265.8	266.0	266.1	266.2	269.6	269.7	269.8	269.9	270.0	270.2	270.2
DSM	GWH	10.7	11.4	11.9	11.9	11.9	11.9	11.9	11.1	10.3	9.5	8.7	7.9
NEM	GWH	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	3.8	4.0	4.2	4.3
Losses	GWH	43.5	43.5	43.6	43.6	43.6	44.1	44.2	44.2	44.2	44.2	44.2	44.3
Net Sales (excl losses)	GWH	208.8	208.1	207.6	207.5	207.5	210.2	210.1	210.8	211.6	212.3	213.1	213.7
LOLH	HOURS	4	21	77	2	14	-	-	-	7	-	23	19
FUEL													
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	366	364	364	364	364	370	369	370	372	374	375	377
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS													
Energy from Renewables	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	9%	9%
CO_2	TONS (000)	170	169	169	169	169	172	172	172	173	174	174	175
CO_2 Intensity	LBS/MWH	1,548	1,540	1,541	1,542	1,542	1,548	1,546	1,551	1,560	1,567	1,570	1,579
NO_X	TONS (000)	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Table C-10
CUC System Cost Summary for Case 14: HFO with 10MW PV

		Levelized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NET SALES	GWH	**219.8**	**218.0**	**218.9**	**219.9**	**220.2**	**219.2**	**219.2**	**219.4**	**219.4**	**219.4**	**219.5**	**219.5**	**219.5**	**219.5**
AMORTIZED CAPITAL COSTS															
Capacity Charge - Generation	$000	15,395	-	-	12,108	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS															
Fuel - Existing	$000	21,708	45,597	48,359	23,106	9,854	10,406	11,077	11,685	12,359	13,186	14,026	14,651	15,583	16,659
Fuel - New	$000	43,581	-	-	20,112	29,668	31,390	33,276	35,252	37,293	39,426	41,646	44,302	46,922	49,541
Variable O&M - Existing	$000	2,416	4,580	4,793	2,518	1,382	1,435	1,499	1,555	1,619	1,694	1,777	1,829	1,909	2,000
Variable O&M - New	$000	4,108	-	-	2,676	3,813	3,897	3,996	4,103	4,208	4,313	4,419	4,556	4,678	4,792
Fixed O&M - Existing	$000	1,812	2,637	2,729	1,697	1,186	1,231	1,278	1,326	1,377	1,429	1,484	1,540	1,599	1,660
Fixed O&M - New	$000	7,602	-	-	4,817	7,365	7,536	7,711	7,890	8,073	8,260	8,452	8,648	8,848	9,054
Renewable	$000	2,584	-	-	610	3,090	3,105	3,103	3,112	3,120	3,136	3,135	3,142	3,149	3,167
DSM	$000	371	607	312	322	333	344	355	367	379	391	404	418	431	446
TOTAL COSTS	**$000**	**79,356**	**53,421**	**56,193**	**67,967**	**74,853**	**77,506**	**80,457**	**83,452**	**86,589**	**89,998**	**93,505**	**97,249**	**101,282**	**105,479**
	$/MWh	**361.1**	**245.1**	**256.7**	**309.1**	**340.0**	**353.6**	**367.0**	**380.4**	**394.6**	**410.1**	**426.0**	**443.1**	**461.4**	**480.5**

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NET SALES	GWH	**219.5**	**219.4**	**219.5**	**219.5**	**219.4**	**222.1**	**222.0**	**221.9**	**221.9**	**221.8**	**221.8**	**221.6**
AMORTIZED CAPITAL COSTS													
Capacity Charge - Generation	$000	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162
Debt Service - T & D	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS													
Fuel - Existing	$000	17,739	18,621	19,982	21,112	22,433	23,996	25,378	27,319	28,515	30,288	32,512	34,388
Fuel - New	$000	52,460	55,654	58,987	62,745	66,802	71,832	76,308	81,082	86,910	92,836	99,163	105,145
Variable O&M - Existing	$000	2,089	2,171	2,270	2,363	2,463	2,584	2,688	2,840	2,920	3,042	3,189	3,327
Variable O&M - New	$000	4,920	5,062	5,201	5,367	5,542	5,796	5,983	6,174	6,433	6,674	6,917	7,162
Fixed O&M - Existing	$000	1,723	1,789	1,857	1,928	2,002	2,078	2,158	2,240	2,326	2,415	2,507	2,603
Fixed O&M - New	$000	9,264	9,479	9,698	9,923	10,154	10,389	10,630	10,877	11,129	11,387	11,652	11,922
Renewable	$000	3,166	3,173	3,181	3,196	3,196	3,204	3,212	3,228	3,227	3,234	3,242	3,260
DSM	$000	460	476	491	507	524	542	559	-	-	-	-	-
TOTAL COSTS	**$000**	**109,983**	**114,586**	**119,830**	**125,304**	**131,277**	**138,584**	**145,078**	**151,923**	**159,623**	**168,040**	**177,344**	**185,970**
	$/MWh	**501.1**	**522.2**	**545.9**	**571.0**	**598.4**	**624.1**	**653.5**	**684.6**	**719.5**	**757.6**	**799.7**	**839.1**

Table C-11
CUC System Capacity Summary for Case 14: HFO with 10MW PV

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPACITY														
Existing Thermal	MW	98.7	98.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7
New Thermal	MW	-	-	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9
New Renewables	MW	-	-	-	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.3
TOTAL CAPACITY		98.7	98.7	87.6	90.1	90.1	90.1	90.0	90.0	90.0	90.0	90.0	90.0	89.9
PEAK DEMAND	MW	42.9	43.3	43.5	43.6	43.5	43.6	43.7	43.7	43.6	43.8	43.8	43.8	43.7
DSM	MW	0.3	0.5	0.8	1.1	1.3	1.6	1.9	2.1	2.3	2.5	2.7	2.9	3.1
NEM	MW	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Peak (net of DSM/NEM)	MW	42.7	42.7	42.6	42.4	41.9	41.8	41.6	41.3	41.0	41.0	40.8	40.6	40.3
Reserve Requirements	MW	42.7	42.7	30.4	30.4	30.4	30.4	30.5	30.5	30.5	30.5	30.5	30.5	30.5
Total Capacity Requirements	MW	85.3	85.4	73.0	72.9	72.4	72.3	72.0	71.8	71.5	71.4	71.3	71.1	70.8
Surplus/(Deficiency)	MW	13.4	13.3	14.6	17.2	17.7	17.8	18.0	18.2	18.5	18.5	18.7	18.8	19.1

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CAPACITY													
Existing Thermal	MW	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7
New Thermal	MW	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9
New Renewables	MW	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.1
TOTAL CAPACITY		89.9	89.9	89.9	89.9	89.9	89.8	89.8	89.8	89.8	89.8	89.8	89.7
PEAK DEMAND	MW	43.9	43.9	43.9	43.8	43.9	44.3	44.3	44.2	44.4	44.4	44.4	44.3
DSM	MW	3.3	3.5	3.6	3.6	3.6	3.6	3.6	3.3	3.1	2.8	2.5	2.3
NEM	MW	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6
Peak (net of DSM/NEM)	MW	40.2	40.1	39.9	39.8	39.9	40.3	40.3	40.4	40.8	41.1	41.3	41.5
Reserve Requirements	MW	30.5	30.5	30.5	30.5	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
Total Capacity Requirements	MW	70.8	70.6	70.4	70.3	70.5	70.8	70.9	71.0	71.4	71.7	71.9	72.1
Surplus/(Deficiency)	MW	19.2	19.3	19.4	19.5	19.4	19.0	19.0	18.8	18.4	18.1	17.8	17.7

Table C-12a
CUC System Operations Summary for Case 14: HFO with 10MW PV

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
GENERATION														
Existing Thermal	GWH	260.1	260.5	110.4	38.1	37.8	38.1	37.9	37.9	38.1	38.6	37.8	37.9	38.3
New Thermal	GWH	-	-	146.5	203.0	201.6	200.9	200.5	199.9	199.1	198.2	198.5	197.9	196.8
New Renewables	GWH	-	-	3.8	19.1	19.0	18.8	18.7	18.5	18.5	18.3	18.1	18.0	17.9
TOTAL GENERATION		260.1	260.5	260.7	260.3	258.5	257.8	257.1	256.3	255.7	255.0	254.4	253.7	253.0
Excess Generation	GWH	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	-	(0.0)	-	(0.0)	(0.0)
Emergency Energy	GWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	0.0	-	0.0	0.0
System Load	GWH	260.7	261.9	263.2	263.9	264.1	264.3	264.6	264.8	264.9	265.1	265.3	265.4	265.6
DSM	GWH	0.8	1.6	2.4	3.2	4.0	4.8	5.6	6.4	7.2	7.8	8.5	9.2	10.0
NEM	GWH	0.0	0.1	0.2	0.5	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.5	2.6
Losses	GWH	42.7	42.9	43.1	43.2	43.3	43.3	43.3	43.4	43.4	43.4	43.4	43.5	43.5
Net Sales (excl losses)	GWH	217.2	217.3	217.5	217.0	215.1	214.4	213.8	213.0	212.3	211.6	210.9	210.3	209.5
LOLH	HOURS	6	27	1	5	15	9	4	-	-	4	-	1	4
FUEL														
HFO	BBL (000)	-	-	218	303	301	299	299	298	297	295	296	295	293
LFO	BBL (000)	429	430	186	68	68	68	68	68	68	69	67	68	68
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS														
Energy from Renewables	%	0%	0%	2%	9%	10%	10%	10%	10%	10%	10%	10%	10%	10%
CO_2	TONS (000)	199	200	206	197	196	195	195	194	194	193	193	193	192
CO_2 Intensity	LBS/MWH	1,827	1,823	1,869	1,789	1,785	1,780	1,775	1,770	1,766	1,761	1,758	1,754	1,749
NO_X	TONS (000)	2.9	2.9	2.8	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6

Table C-12b
CUC System Operations Summary for Case 14: HFO with 10MW PV

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
GENERATION													
Existing Thermal	GWH	38.5	38.3	38.5	38.4	38.5	38.9	38.8	39.7	38.8	38.8	39.1	39.3
New Thermal	GWH	196.2	195.8	195.1	195.3	195.5	198.3	198.4	198.4	200.3	201.2	201.7	202.3
New Renewables	GWH	17.7	17.6	17.5	17.4	17.2	17.1	16.9	16.9	16.7	16.6	16.4	16.4
TOTAL GENERATION		252.4	251.7	251.1	251.1	251.1	254.3	254.2	254.9	255.8	256.5	257.3	258.0
Excess Generation	GWH	-	(0.0)	(0.0)	-	-	-	-	-	-	-	(0.0)	(0.0)
Emergency Energy	GWH	0.0	-	0.0	0.0	0.0	0.0	0.1	0.1	0.0	-	0.0	0.0
System Load	GWH	265.7	265.8	266.0	266.1	266.2	269.6	269.7	269.8	269.9	270.0	270.2	270.2
DSM	GWH	10.7	11.4	11.9	11.9	11.9	11.9	11.9	11.1	10.3	9.5	8.7	7.9
NEM	GWH	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	3.8	4.0	4.2	4.3
Losses	GWH	43.5	43.5	43.6	43.6	43.6	44.1	44.2	44.2	44.2	44.2	44.2	44.3
Net Sales (excl losses)	GWH	208.8	208.1	207.6	207.5	207.5	210.2	210.1	210.8	211.6	212.3	213.1	213.7
LOLH	HOURS	1	-	76	24	16	3	24	39	3	-	12	9
FUEL													
HFO	BBL (000)	292	292	291	291	291	296	296	296	298	300	301	302
LFO	BBL (000)	69	68	69	69	69	69	69	70	69	69	70	70
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS													
Energy from Renewables	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	9%	9%
CO_2	TONS (000)	192	191	191	191	191	194	194	194	195	196	197	197
CO_2 Intensity	LBS/MWH	1,746	1,741	1,739	1,739	1,742	1,744	1,745	1,750	1,759	1,767	1,774	1,780
NO_X	TONS (000)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7

Table C-13
CUC System Cost Summary for Case 16: LNG-All with 10MW PV

		Levelized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NET SALES	GWH	**219.8**	**218.0**	**218.9**	**219.9**	**220.2**	**219.2**	**219.2**	**219.4**	**219.4**	**219.4**	**219.5**	**219.5**	**219.5**	**219.5**
AMORTIZED CAPITAL COSTS		0	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Charge - Generation	$000	5,940	-	-	-	-	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937
Debt Service - LNG Infrastructure	$000	4,170	-	-	-	-	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732
OPERATING COSTS		0	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel - Existing	$000	12,450	45,598	48,334	51,014	51,275	92	135	125	107	146	129	186	164	206
Fuel - New	$000	40,693	-	-	-	-	39,450	40,855	42,142	43,813	45,378	46,982	49,046	50,337	51,703
Variable O&M - Existing	$000	1,217	4,582	4,780	4,952	4,894	8	11	10	9	12	10	14	13	16
Variable O&M - New	$000	3,937	-	-	-	-	3,992	4,108	4,233	4,367	4,503	4,642	4,789	4,932	5,084
Fixed O&M - Existing	$000	946	2,637	2,729	2,825	2,924	250	258	266	275	284	294	303	313	324
Fixed O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	$000	2,584	-	-	610	3,090	3,105	3,103	3,112	3,120	3,136	3,135	3,142	3,149	3,167
DSM	$000	371	607	312	322	333	344	355	367	379	391	404	418	431	446
TOTAL COSTS	**$000**	**63,579**	**53,423**	**56,156**	**59,723**	**62,516**	**60,909**	**62,495**	**63,923**	**65,738**	**67,520**	**69,265**	**71,567**	**73,008**	**74,613**
	$/MWh	**289.3**	**245.1**	**256.5**	**271.6**	**283.9**	**277.9**	**285.1**	**291.4**	**299.6**	**307.7**	**315.6**	**326.1**	**332.6**	**339.9**

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NET SALES	GWH	**219.5**	**219.4**	**219.5**	**219.5**	**219.4**	**222.1**	**222.0**	**221.9**	**221.9**	**221.8**	**221.8**	**221.6**
AMORTIZED CAPITAL COSTS		-	-	-	-	-	-	-	-	-	-	-	-
Capacity Charge - Generation	$000	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937
Debt Service - T & D	$000	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	-
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS		-	-	-	-	-	-	-	-	-	-	-	-
Fuel - Existing	$000	109	145	158	145	261	236	225	314	433	281	399	385
Fuel - New	$000	53,245	54,743	57,084	59,531	62,008	65,695	68,233	71,377	74,143	77,561	82,323	87,156
Variable O&M - Existing	$000	8	11	11	10	19	17	16	22	30	19	27	25
Variable O&M - New	$000	5,240	5,407	5,570	5,753	5,937	6,234	6,431	6,669	6,911	7,163	7,435	7,689
Fixed O&M - Existing	$000	334	345	357	369	381	393	406	420	433	448	463	478
Fixed O&M - New	$000	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	$000	3,166	3,173	3,181	3,196	3,196	3,204	3,212	3,228	3,227	3,234	3,242	3,260
DSM	$000	460	476	491	507	524	542	559	-	-	-	-	-
TOTAL COSTS	**$000**	**76,231**	**77,970**	**80,521**	**83,179**	**85,995**	**89,990**	**92,752**	**95,699**	**98,846**	**102,374**	**107,558**	**106,930**
	$/MWh	**347.4**	**355.3**	**366.8**	**379.0**	**392.0**	**405.2**	**417.8**	**431.2**	**445.5**	**461.6**	**485.0**	**482.5**

Table C-14
CUC System Capacity Summary for Case 16: LNG-All with 10MW PV

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPACITY														
Existing Thermal	MW	98.7	98.7	98.7	98.7	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
New Thermal	MW	-	-	-	-	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3
New Renewables	MW	-	-	-	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.3
TOTAL CAPACITY		98.7	98.7	98.7	101.2	76.8	76.8	76.7	76.7	76.7	76.7	76.7	76.7	76.6
PEAK DEMAND	MW	42.9	43.3	43.5	43.6	43.5	43.6	43.7	43.7	43.6	43.8	43.8	43.8	43.7
DSM	MW	0.3	0.5	0.8	1.1	1.3	1.6	1.9	2.1	2.3	2.5	2.7	2.9	3.1
NEM	MW	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Peak (net of DSM/NEM)	MW	42.7	42.7	42.6	42.4	41.9	41.8	41.6	41.3	41.0	41.0	40.8	40.6	40.3
Reserve Requirements	MW	42.7	42.7	42.6	42.4	28.0	28.0	28.1	28.1	28.1	28.1	28.1	28.1	28.1
Total Capacity Requirements	MW	85.3	85.4	85.3	84.9	70.0	69.9	69.6	69.4	69.1	69.0	68.9	68.7	68.4
Surplus/(Deficiency)	MW	13.4	13.3	13.4	16.3	6.8	6.9	7.1	7.3	7.6	7.6	7.8	7.9	8.2

		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CAPACITY													
Existing Thermal	MW	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
New Thermal	MW	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3
New Renewables	MW	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.1
TOTAL CAPACITY		76.6	76.6	76.6	76.6	76.6	76.5	76.5	76.5	76.5	76.5	76.5	76.4
PEAK DEMAND	MW	43.9	43.9	43.9	43.8	43.9	44.3	44.3	44.2	44.4	44.4	44.4	44.3
DSM	MW	3.3	3.5	3.6	3.6	3.6	3.6	3.6	3.3	3.1	2.8	2.5	2.3
NEM	MW	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6
Peak (net of DSM/NEM)	MW	40.2	40.1	39.9	39.8	39.9	40.3	40.3	40.4	40.8	41.1	41.3	41.5
Reserve Requirements	MW	28.1	28.1	28.1	28.1	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2
Total Capacity Requirements	MW	68.4	68.2	68.0	67.9	68.1	68.4	68.5	68.6	69.0	69.3	69.5	69.7
Surplus/(Deficiency)	MW	8.3	8.4	8.5	8.6	8.5	8.1	8.1	7.9	7.5	7.2	6.9	6.8

Table C-15a
CUC System Operations Summary for Case 16: LNG-All with 10MW PV

CUC TOTAL		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
GENERATION														
Existing Thermal	GWH	260.1	260.5	257.0	241.2	0.4	0.5	0.4	0.4	0.5	0.4	0.5	0.4	0.5
New Thermal	GWH	-	-	-	-	240.5	239.7	239.0	238.7	238.2	237.7	237.3	236.7	236.1
New Renewables	GWH	-	-	3.8	19.1	19.0	18.8	18.7	18.5	18.5	18.3	18.1	18.0	17.9
TOTAL GENERATION		260.1	260.5	260.7	260.3	259.9	259.0	258.1	257.6	257.1	256.4	256.0	255.1	254.5
Excess Generation	GWH	(0.2)	(0.2)	(0.2)	(0.1)	(1.5)	(1.3)	(1.1)	(1.3)	(1.5)	(1.4)	(1.6)	(1.4)	(1.5)
Emergency Energy	GWH	0.0	0.0	-	0.0	0.0	-	0.0	-	-	0.0	-	0.0	-
System Load	GWH	260.7	261.9	263.2	263.9	264.1	264.3	264.6	264.8	264.9	265.1	265.3	265.4	265.6
DSM	GWH	0.8	1.6	2.4	3.2	4.0	4.8	5.6	6.4	7.2	7.8	8.5	9.2	10.0
NEM	GWH	0.0	0.1	0.2	0.5	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.5	2.6
Losses	GWH	42.7	42.9	43.1	43.2	43.3	43.3	43.3	43.4	43.4	43.4	43.4	43.5	43.5
Net Sales (excl losses)	GWH	217.2	217.3	217.5	217.0	215.1	214.4	213.8	213.0	212.3	211.6	210.9	210.3	209.5
LOLH	HOURS	6	20	-	1	21	-	3	-	-	4	-	21	-
FUEL														
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	429	429	423	399	1	1	1	1	1	1	1	1	1
LNG	GBTU	-	-	-	-	2,285	2,276	2,270	2,267	2,262	2,258	2,254	2,248	2,242
EMISSIONS / RPS														
Energy from Renewables	%	0%	0%	2%	9%	10%	10%	10%	10%	10%	10%	10%	10%	10%
CO_2	TONS (000)	199	199	196	185	134	134	133	133	133	132	132	132	132
CO_2 Intensity	LBS/MWH	1,827	1,822	1,787	1,683	1,222	1,218	1,214	1,211	1,210	1,207	1,206	1,201	1,199
NO_X	TONS (000)	2.9	2.9	2.9	2.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Table C-15b
CUC System Operations Summary for Case 16: LNG-All with 10MW PV

CUC TOTAL		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
GENERATION													
Existing Thermal	GWH	0.2	0.3	0.3	0.3	0.5	0.4	0.4	0.5	0.6	0.4	0.5	0.5
New Thermal	GWH	235.6	235.3	234.6	234.6	234.4	238.3	238.0	238.9	239.7	240.5	241.7	242.0
New Renewables	GWH	17.7	17.6	17.5	17.4	17.2	17.1	16.9	16.9	16.7	16.6	16.4	16.4
TOTAL GENERATION		253.6	253.2	252.4	252.3	252.1	255.8	255.3	256.3	257.0	257.5	258.6	258.8
Excess Generation	GWH	(1.2)	(1.6)	(1.3)	(1.2)	(1.0)	(1.4)	(1.0)	(1.3)	(1.2)	(0.9)	(1.3)	(0.8)
Emergency Energy	GWH	0.0	-	0.0	0.0	-	0.0	-	0.0	-	0.0	-	-
System Load	GWH	265.7	265.8	266.0	266.1	266.2	269.6	269.7	269.8	269.9	270.0	270.2	270.2
DSM	GWH	10.7	11.4	11.9	11.9	11.9	11.9	11.9	11.1	10.3	9.5	8.7	7.9
NEM	GWH	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	3.8	4.0	4.2	4.3
Losses	GWH	43.5	43.5	43.6	43.6	43.6	44.1	44.2	44.2	44.2	44.2	44.2	44.3
Net Sales (excl losses)	GWH	208.8	208.1	207.6	207.5	207.5	210.2	210.1	210.8	211.6	212.3	213.1	213.7
LOLH	HOURS	6	-	10	40	-	1	-	35	-	4	-	-
FUEL													
HFO	BBL (000)	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	0	1	1	1	1	1	1	1	1	1	1	1
LNG	GBTU	2,237	2,235	2,229	2,228	2,226	2,263	2,260	2,269	2,276	2,283	2,295	2,298
EMISSIONS / RPS													
Energy from Renewables	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	9%	9%
CO_2	TONS (000)	131	131	131	131	131	133	132	133	134	134	135	135
CO_2 Intensity	LBS/MWH	1,195	1,194	1,190	1,190	1,191	1,195	1,194	1,200	1,205	1,207	1,214	1,216
NO_X	TONS (000)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

$/MWh: dollars per megawatt-hour

~A~

AC: alternating current

AEO: Annual Energy Outlook

~B~

BAU: Business as Usual

~C~

CNMI: Commonwealth of Northern Mariana Islands

CO_2: carbon dioxide

CPI: Consumer Price Index

CUC: Commonwealth Utilities Corporation

~D~

DOC: Department of Commerce

DR: demand respons

DSM: demand-side management

~E~

EE: energy efficiency

EIA: Energy Information Administration

EPA: Environmental Protection Agency

EPC: engineer, procure and construct

~F~

~G~

GDP: Gross Domestic Product

GPA: Guam Power Authority

GWh: gigawatt-hour

~H~

HFO: heavy fuel oil

~I-J~

ID: induced draft

IPP: independent power producer

IRP: Integrated Resource Plan

ISO: International Standard Organization

ITC: investment tax credits

~K~

~L~

LCOE: Levelized Cost of Energy

LEAC: Levelized Energy Adjustment Clause

LEDs: light emitting diodes

Leidos: Leidos Engineering, LLC

LFO: light fuel oil

LNG: liquefied natural gas

LOLP: Loss o Load Probability

~M~

MMBtu: 1,000,000 British thermal units

MPOS: Mean of Platts Singapore

MW: megawatt, 1,000 kilowatts

MW_{AC}: megawatt-alternating current

~N~

NAAQS: National Ambient Air Quality Standards

NAVD: North American Vertical Datum

NREL: National Renewable Energy Laboratory

~O~

O&M: Operation and Maintenance

OIA: Office of Insular Affairs

~P~

PPA: Power Purchase Agreement

PROMOD®: ABB's PROMOC IV

PV: photovoltaic

~Q~

~R~

RFI: Request for Information

RFP: Request for Proposals for Energy Supply

RPS: Renewable Portfolio Standard

~S~

SSC: Source Selection Committee

~T~

TMY: Typical Meteorological Year

TRC: Total Resource Cost

~U~

U.S.: United States

US GDPIPD: U.S. GDP Implicit Price Deflator

~V~

~W-X-Y-Z~