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GOVERNMENT OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN	**CASE NO.:** NEPR-MI-2021-0012 ~~CEPR-AP-2018-0001~~ **SUBJECT**: Motion in Compliance; Feasibility Study for Improvements to Hydroelectrical System

MOTION IN COMPLIANCE WITH ORDER ENTERED ON JULY 23, 2021

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COMES NOW, the Puerto Rico Electric Power Authority, through its counsel of record and respectfully sets forth and prays:

I. INTRODUCTION

1. On August 24, 2020, the Puerto Rico Energy Bureau of the Public Service Regulatory Board (the "Energy Bureau") entered *Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan* (the "Final IRP Order") directing the Puerto Rico Electric Power Authority (the "Authority") to, among other things, complete and submit a feasibility study of refurbishing each of the hydroelectric facilities (the "Hydro Study"). Pursuant to the Final IRP Order, the deadline to present the Hydro Study was February 22, 2021.

2. On February 22, 2021, the Authority submitted to the Energy Bureau a *Motion to Submit Status Report of Feasibility Study for Improvement of PREPA's Hydroelectric System and to Request Extension of Time to Submit Final Study* (the "Request for Extension") through which the Authority requested an extension of time until June 30, 2021, to submit the Hydro Study.

3. On June 30, 2021, the Authority, in compliance with the Final IRP Order and the deadline proposed in the Request for Extension submitted, among other things, the Final Hydro Study and feasibility studies of Tasks 500 and 600 (the "Feasibility Studies"). The latter were submitted under seal.

4. On July 23, 2021, Energy Bureau issued a *Resolution and Order* (the "Order") directing the Authority to file on or before today July 29, 2021, a public version of the Feasibility Studies.

5. In compliance with the Order, PREPA submits unredacted versions of the Feasibility Studies. Exhibits A and B.

WHEREFORE, the Authority herein requests the Energy Bureau to find the Authority in compliance with the Order.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 29th day of July 2021.

s/ Katiuska Bolaños Lugo
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CERTIFICATE OF SERVICE

It is hereby certified that, on this same date I have filed the above motion using the Energy Bureau's Electronic Filing System, at the following address: http://radicacion.energia.pr.gov and that a courtesy copy of the filing was sent via e-mail to: sierra@arctas.com; tonytorres2366@gmail.com; cfl@mcvpr.com; gnr@mcvpr.com; info@liga.coop; amaneser2020@gmail.com; hrivera@oipc.pr.gov; jrivera@cnslpr.com; carlos.reyes@ecoelectrica.com; ccf@tcmrslaw.com; manuelgabrielfernandez@gmail.com; acarbo@edf.org; pedrosaade5@gmail.com; rmurthy@earthjustice.org; rstgo2@gmail.com; larroyo@earthjustice.org; jluebkemann@earthjustice.org; acasellas@amgprlaw.com; loliver@amgprlaw.com; epo@amgprlaw.com; robert.berezin@weil.com; marcia.goldstein@weil.com; jonathan.polkes@weil.com; gregory.silbert@weil.com; agraitfe@agraitlawpr.com; maortiz@lvprlaw.com; rnegron@dnlawpr.com; castrodieppalaw@gmail.com; voxpopulix@gmail.com; paul.demoudt@shell.com; javier.ruajovet@sunrun.com; escott@ferraiuoli.com; SProctor@huntonak.com; GiaCribbs@huntonak.com; mgrpcorp@gmail.com; aconer.pr@gmail.com; axel.colon@aes.com; rtorbert@rmi.org; apagan@mpmlawpr.com; sboxerman@sidley.com; bmundel@sidley.com.

In San Juan, Puerto Rico, this 29th day of July 2021.

s/ Katiuska Bolaños Lugo
Katiuska Bolaños Lugo

Exhibit A

Feasibility Study for Improvements to Hydro Electrical System- Task 500 Frequency Response and Remote-Control Memorandum dated May 13, 2021

FINAL

FEASIBILITY STUDY FOR IMPROVEMENTS TO HYDROELECTRICAL SYSTEM

TASK 500 – FREQUENCY RESPONSE AND REMOTE CONTROL MEMORANDUM

B&V PROJECT NO. 407635.45.0000

PREPARED FOR

Puerto Rico Electric Power Authority

13 MAY 2021

BLACK & VEATCH
Building a world of difference.

Table of Contents

This report was prepared by the following Black & Veatch personnel:

Randy Boyce - Hydro Project Manager

Dianys Arocho - Engineering Manager

Aaron Lemke - Hydropower Technical Lead, Mechanical / Civil

Bruce Benson - Hydropower Technical Lead, Electrical / Control

1.0 Introduction

This technical memorandum is part of the feasibility study project by Black & Veatch to identify improvements to Puerto Rico Electric Power Authority's (PREPA's) hydroelectric facilities. This memorandum summarizes the Task 500 evaluation of the generation unit frequency response and potential for remote control.

The following hydroelectrical facilities are included in this study:

1) Dos Bocas (Units 1, 2 & 3)
2) Caonillas 1 (Units 1-1 & 1-2)
3) Caonillas 2 (Unit 2-1)
4) Toro Negro 1 (Units 1-1, 1-2, 1-3, & 1-4)
5) Toro Negro 2 (Unit 2-1)
6) Garzas 1 (Unit 1-1 & 1-2)
7) Garzas 2 (Units 2-1)
8) Yauco 1 (Unit 1-1)
9) Yauco 2 (Units 2-1 & 2-2)
10) Río Blanco (Units 1-1 & 1-2)

Following is the Task 500 scope for these hydroelectric facilities:

- Potential for Automated Frequency Response. The Dos Bocas, Caonillas 1, Yauco 1 and Yauco 2 units have frequency control capabilities. For the remaining six hydroelectrical facilities, the turbine governors will be evaluated to determine their ability to automatically respond to frequency variations within the electrical system.
- Potential for Remote Control. PREPA has an Energy Control Center (ECC) in Monacillo, San Juan; which currently provides voltage and power control remotely for Yauco 1 and 2 after they are locally started and put online manually. All ten of the hydroelectrical facilities listed above will be evaluated to determine the existing potential for remote startup, shutdown, voltage and power control from the ECC. The evaluation will address communication between the facilities and the ECC.

Each of the ten hydroelectric sites were visited the week of February 8, 2021. Black & Veatch will use the data provided by PREPA and the information gathered during these site visits to evaluate the frequency response and remote control capabilities for these facilities.

2.0 Executive Summary

The hydroelectrical facilities were evaluated for their potential to respond automatically to system frequency deviations and their potential for remote operation from the ECC. Following is a summary of the evaluations.

Automated Frequency Response

All of the facilities listed on Section 1.0 were evaluated to determine their ability to automatically respond to frequency deviations on the grid. The Caonillas 1 facility is the only plant that has modern, digital governors with programmable logic controllers (PLCs) for unit operation. All the other facilities have mechanical governors. For facilities that have mechanical governors, there is a flyball system that mechanically reacts automatically to changes in unit speed (grid frequency). If the mechanical governors are tuned and working properly, they should provide automatic response to frequency changes. The Toro Negro 1 facility, Units 1-1, 1-2 and 1-3 (excluding Unit 1-4) were the only units identified that were not designed to have the ability to provide an automatic frequency response; they only have needle positioners and not governors. Request that PREPA confirm the evaluations below to match the current condition / frequency response capability of each facility. To modernize the facilities, the mechanical governors can be converted to digital with a new PLC and operator interface for turbine controls. The digital conversion will also include mechanical modifications to the hydraulic system, new electro-hydraulic interface with distributors, needles and deflectors and additional instrumentation.

Remote Control

Facilities were also evaluated to identify their potential for remote control from the ECC. A reliable communication system and Supervisory Control and Data Acquisition (SCADA) interface with the unit equipment will provide automated data gathering, instantaneously giving the ECC the most up-to-date and accurate generation information. To facilitate remote operation or just monitoring, the communication system to some facilities will need to be repaired. Communication technologies can be evaluated to determine if licensed microwave, fiber optic cables on the transmission lines, or other systems will provide reliable communication. Many of the SCADA systems at the facilities are outdated and some have lost functionality. The existing SCADA systems include a combination of HSQ Technology and Harris RTU hardware. The SCADA system can be standardized to simplify maintenance, troubleshooting and reduce spare inventory. In order to support remote operation, modifications to the SCADA system would be required; however, at some facilities it may not be practical to invest in changes to these older systems.

Similar to Yauco 1, modifications to the other facilities can be made to allow remote load and voltage control from the ECC. Additional modifications to the facilities would be required to provide full automation including remote startup (from standstill), shutdown and synchronization of the unit to the grid as well as online load and voltage control. Caonillas 1 is the only fully automated facility evaluated with remote startup, shutdown, load and voltage control capabilities from Dos Bocas. This functionality could be extended to the ECC.

While it may be possible to modify some of the existing governor and voltage regulators to interface SCADA for remote load and voltage control, due to the age and obsolescence of the equipment it is not really practical to invest in extensive modifications instead of upgrades. An overall modern system would have the SCADA system communicating with the plant control, protection and metering system. A typical modern plant control system includes processors (PLCs) for unit / governor control and a local operator workstation with graphic screens for control, monitoring and alarm management. A modern excitation system can be configured for communication with the unit controller and workstation. The SCADA system communicates directly with the plant control system for remote monitoring and control, eliminating the need for hardwired SCADA inputs/outputs (I/O) and providing access to more data to the ECC. Electrical metering can communicate data for display on the local workstation and to SCADA for ECC use.

A standard configuration can be developed for SCADA, unit / governor control, excitation, protection, metering and local operator interface. By standardizing on the same unit / governor control hardware and configuration it will make it easier for technicians to maintain the system, add points if necessary and troubleshoot problems. By standardizing on the operator workstation and graphics, it will make it easier for rangers to operate units and respond to alarms at multiple plants. By standardizing on hardware, the amount of spares required can also be reduced. Eliminating electromechanical relays and developing a standard for digital multi-function relays and metering can provide additional data to the ECC, provide historical data for evaluating electrical trips and reduce calibration and maintenance. Standard equipment in the facilities will help the ECC standardize on their SCADA interface for remote monitoring and control.

An overall plan can be developed establishing the standard design and configurations for modernization and upgrade of the plant and SCADA systems. Each facility can be evaluated to identify the desired level of automation and other site specific requirements and the standard configurations can be tailored accordingly. The plan can be implemented in phases in coordination with other projects and hydroelectric system priorities.

3.0 General Information – Frequency Response Evaluation

The governor controls the speed and power output of the turbine. In the event of a frequency deviation on the transmission line (system frequency), the governor can be configured to automatically respond in a direction to help restore the frequency. Most of the hydroelectrical facilities in this study have existing mechanical governors. Although this design is outdated, that alone does not justify the need for an upgrade. With proper maintenance and periodic tuning, mechanical governors can provide reliable operation and frequency response. Emerson (formerly the American Governor Company) recommends the governors be overhauled every five to seven years. This section provides general information about mechanical governors and digital governor conversions that will be referenced in the individual facility evaluations below.

The Electrical Power Research Institute (EPRI) published a series of Hydro Life Extension Modernization Guides in 2006. Even though these guides are over 15 years old, they still provide valuable information for evaluating older facilities. These guides are publicly available and will be referenced in this evaluation. The guide Volume 2 for Hydromechanical Equipment describes condition assessment and life extension for the governing equipment. Over time, the governor may experience a change in responsiveness and frequency control stability due to wear in mechanical components. This can be remedied with rehabilitation or replacement of the parts instead of a complete digital conversion.

The U. S. Department of the Interior Bureau of Reclamation (USBR), U. S. Department of Army Corps of Engineers (USACE), U. S. Department of Energy Western Area Power Administration (WAPA) and U. S. Department of Energy Bonneville Power Administration (BPA) published the Federal Replacements Units, Service Lives, Factors report in 2017. This report is publicly available and will also be referenced in this evaluation. According to the USBR report, the service life for a mechanical governor is 50 years and the service life for a digital governor control system is 15 years. The report states the mechanical governor rotating permanent magnet generators and ball heads require maintenance due to considerable wear – note the digital governors do not use these rotating parts.

On January 20, 2021, Black & Veatch conducted a conference call with PREPA personnel including generation, plant management and ECC staff to discuss unit responsiveness issues and requirements. Currently, the electrical system is configured with an alarm setting at +/- 0.2 Hz from the nominal 60 Hz operating frequency, below 59.8 and above 60.2. The generating units get alarms more often than desired and PREPA wants to improve the frequency response of the hydro units. There are no testing or frequency response requirements for individual units to allow connection to the overall system. PREPA's goal is for the units to be able to respond within the +/- 0.2 Hz range and reduce alarms.

IEEE (Institute of Electrical and Electronics Engineers) Standard 125, Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators includes a section on performance specifications and testing for governors. IEEE Standard 1207, Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units, includes sections on performance specifications, field testing and tuning hydroelectric governing systems. Governor supplier's such as Emerson (AGC) and L&S Electric can perform standard testing, tuning and identify modifications to improve performance.

Each hydroelectrical facility is evaluated below to determine their ability to automatically respond to frequency variations. The evaluations include recommendations for governor upgrades or required modifications for each site.

4.0 General Information – Remote Control Evaluation

Currently, Yauco 2 is the only facility in this study with the functioning ability for remote control from the ECC. This section provides general information useful in evaluation of the potential for remote control of the hydroelectrical facilities from the ECC. This information will be referenced in the individual facility evaluations below.

Remote control of the generating units from the ECC requires the following three major components:

- Reliable Communication Infrastructure between facilities.
- SCADA system in the ECC and the facilities.
- Unit Control interface.

Reliable Communication Infrastructure:

Figure 4-1 provides an overview showing the locations of the ten hydroelectrical facilities on the island relative to the ECC.

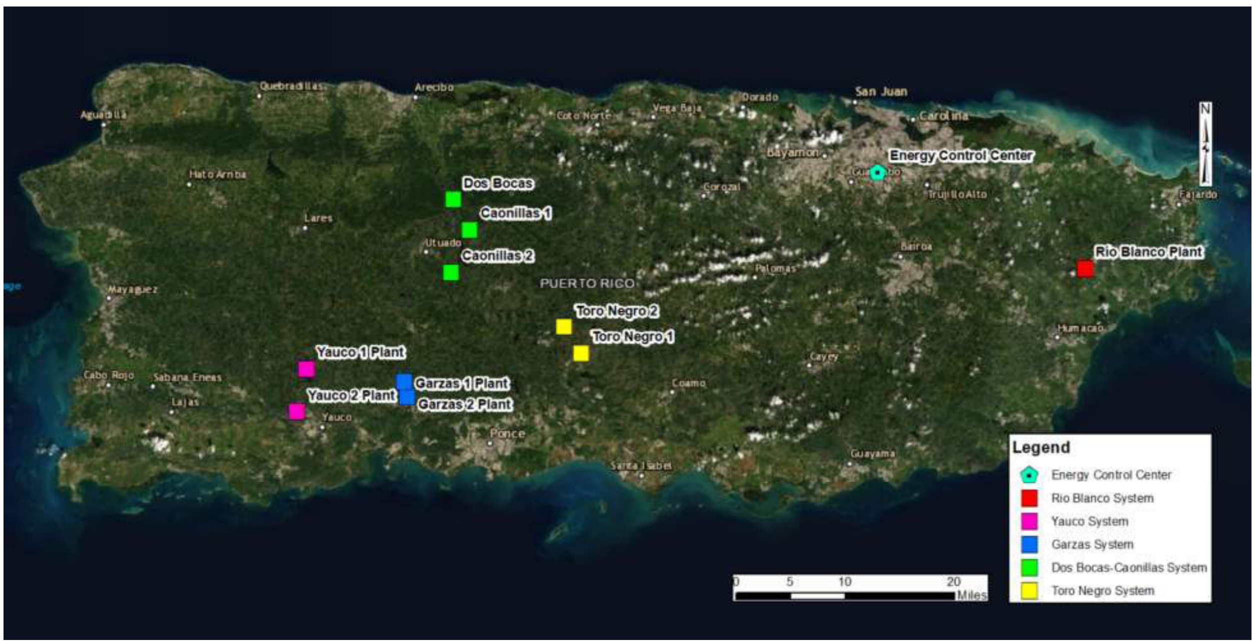


Figure 4-1 Map of Hydroelectrical Facilities and the Energy Control Center

In order for personnel in the ECC to be able to remotely control a unit, there needs to be network communication between the facilities. Currently, PREPA has a communication infrastructure around the island utilizing microwave radio with line-of-sight antennas and fiber optic cables run with the transmission lines.

On February 11, 2021, Black & Veatch personnel reported to PREPA generation and ECC personnel discussions and information gathered during the site visits regarding the communication system. PREPA personnel at the Dos Bocas facility said that when the microwave is operational it works well.

They have experienced issues with power loss at the microwave sites and then the batteries drain down resulting in loss of communication to that site. They expressed the need to investigate increasing the reliability of the microwave system.

In email responses to questions, PREPA indicates the communication systems that are currently down are awaiting funding or resources to fix or replace. The communication system is reported to be adequate when the microwave radios were working and met the required needs. They typically only lost communication when the microwave repeater sites experienced a loss of power or during an equipment outage. The fiber optic link provides more than adequate communication and only experiences a loss when cut or during an equipment outage.

The scope of this task is to identify the potential for remote control at the hydroelectrical facilities. Evaluation and cost analysis to rehabilitate or upgrade the microwave and fiber communication infrastructure is outside the scope of this project.

SCADA System:

For hydro facilities with a working ECC to plant communication network and adequate metering interface, the electrical generation data is automatically gathered by the local Remote Terminal Unit (RTU) and available instantaneously to ECC personnel. For hydro facilities without a working ECC network, personnel at the ECC have to call the local operator each hour and manually log the generation data into their system.

During the site visit to the hydroelectrical facilities, the team asked if there was a functioning SCADA system and network communication back to the ECC. This information will be presented in the individual facility evaluations below. Evaluation and cost analysis to rehabilitate or upgrade the SCADA system in the facilities is outside the scope of this project.

Unit Control interface:

In order to remotely operate a unit, the local equipment will need the ability to accept and implement SCADA hardwired or network communication commands. Currently, the ECC provides voltage and power control remotely for Yauco 1 and 2 after they are locally started and put online manually. This level of semi-automation only requires an interface between the SCADA system and the governor and voltage regulator. If ECC needs to load the unit or adjust vars, it must first be put online (generator connected to the grid) by a local operator.

The Caonillas 1 plant is fully automated and can be remotely controlled from the Dos Bocas hydroelectric facility. In addition to load control, the units can be started and stopped remotely from Dos Bocas. Full automation is defined as the ability to implement a start command and have the control system automatically step-through the startup sequence without additional operator action. The start-up sequence may be completed using hardwired relays or a modern unit programmable logic controller (PLC) or other digital controller. The startup sequence may include the following steps:

- Open the cooling water valve
- Verify / open the turbine inlet valve

- Open needles / wicket gates, unit to speed-no-load
- At 95% speed, enable the excitation system and close the field breaker
- Automatically adjust the turbine speed and voltage to match the generator to the grid
- Verify unit is synchronized, close the generator circuit breaker
- Adjust unit load and voltage to desired setting

For full automation, all of the devices in the startup sequence will need the ability to be automatically controlled.

The scope of this project is to identify the potential for remote startup, shutdown, voltage and power control from the ECC, each facility is evaluated below. A separate study can be conducted to review the startup / shutdown sequence, identify actions the operator performs manually and determine what modifications are required to provide full (or semi) automation.

5.0 Dos Bocas – Caonillas System

The Dos Bocas-Caonillas Hydroelectric System consists of three generating plant developments:

- Dos Bocas
- Caonillas 1
- Caonillas 2

5.1 DOS BOCAS HYDROELECTRIC PLANT

The Dos Bocas powerhouse was constructed in 1942 and contains three 6 MW vertical Francis type turbine generator units. At the time of the site visit, the Unit 1 generator rotor was removed, Unit 2 was not available due to collector rings repair and Unit 3 was available but offline in synchronous mode. Normally offline means the generator breaker is open and unit is stopped, PREPA said their unit was offline in synchronous mode which means the generator was connected to the grid, the unit was spinning / motoring and can provide var support, but is not loaded and not producing MWs.

5.1.1 Potential for Automated Frequency Response

The existing governors are Woodward mechanical-hydraulic types located on the generator floor. The governors were noted as having a good/fast response time and the units can be used for frequency control.

Photo 5-1 Dos Bocas Mechanical Governor

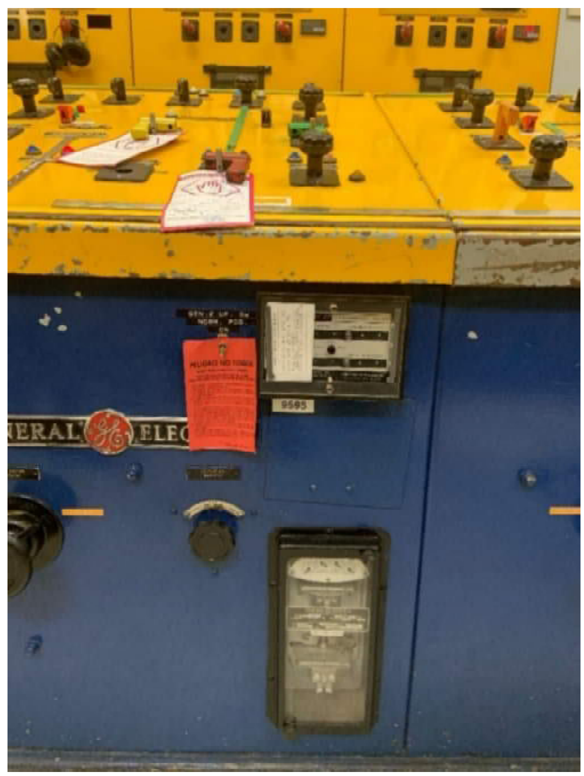


Photo 5-2 Dos Bocas Frequency Relay and Switch

Recommendations: To modernize the facility, the mechanical governors can be converted to digital governors with electronic controllers and touchscreen graphic operator interface terminals (OITs).

5.1.2 Potential for Remote Control

There is a functional fiber optic network to the plant and functioning SCADA system allowing remote monitoring at the ECC. The ECC does not have any remote control of the generating units. There is also microwave communication between Dos Bocas and Caonillas 1 to facilitate remote operation of the Caonillas 1 units.

The generating units are operated from the main control benchboard and control panel in the powerhouse control room. The operator manually steps the unit through the startup sequence.

Unit 2 and Unit 3 have been retrofitted with GE's Ex2100 solid state excitation systems. Unit 1 has the original rotating excitation system which is being evaluated for upgrade to a new solid state excitation system as part of the generator rewind project.

There is a desktop computer in the main control room for remote monitoring and control of the Caonillas 1 units from Dos Bocas. This operator workstation also had screens for monitoring and control of the Dos Bocas Unit 2 and Unit 3 static exciters (see Photo 5-3).

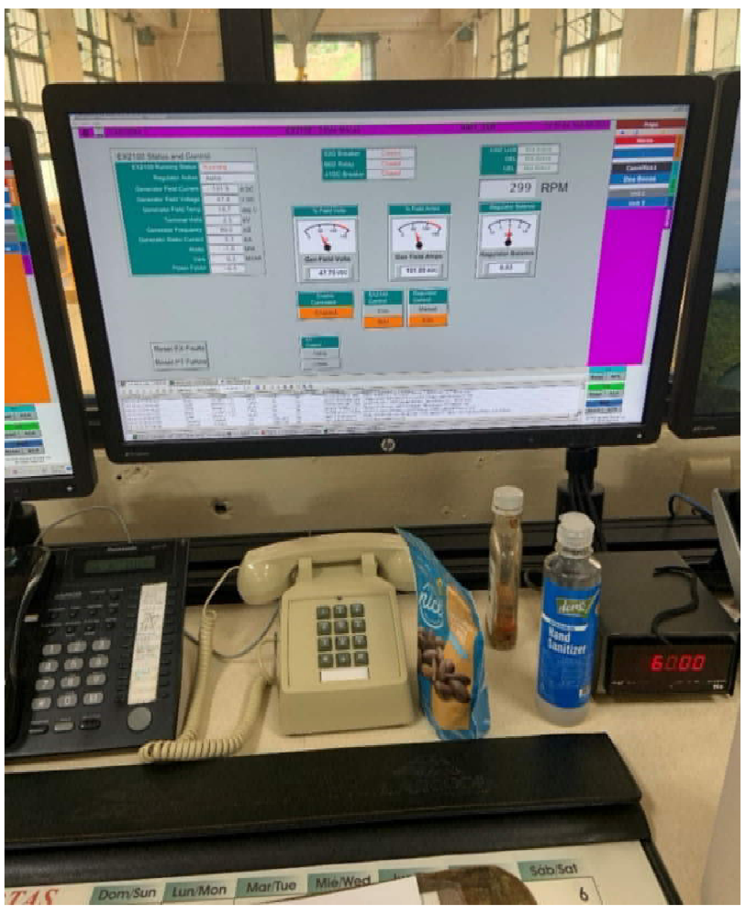


Photo 5-3 Dos Bocas Operator Workstation, Excitation Control

In order to provide ECC remote startup, shutdown control of the units, these manual sequences including synchronization would need to be automated. By automating the speed matching, this would also provide the required interface for remote load control. A SCADA interface to the Units 2 and 3 modern excitation systems that have monitoring and control from the control room operator workstation can be added to provide remote voltage control. The SCADA system would need to be modified to add remote operation functionality.

5.2 CAONILLAS 1 HYDROELECTRIC PLANT

The Caonillas 1 powerhouse was constructed in 1948 and contains two 9 MW vertical Francis type turbine generator units. The Caonillas 1 plant was damaged by flooding from Hurricane Maria in 2017, the turbine level of the powerhouse was flooded and the tailrace silted in. PREPA is planning to have the tailrace dredged and the facility operational by the second trimester of 2022.

5.2.1 Potential for Automated Frequency Response

Both units have modern digital governors using a high pressure hydraulic system with accumulators rated for 2,000 psi. The electronic governor control panel with the GE Fanuc VersaMax programmable logic controller (PLC) was flooded and will be replaced. The new PLC will include automatic frequency response as part of the governor control package.

Photo 5-4 Caonillas 1 Electro-Hydraulic Interface

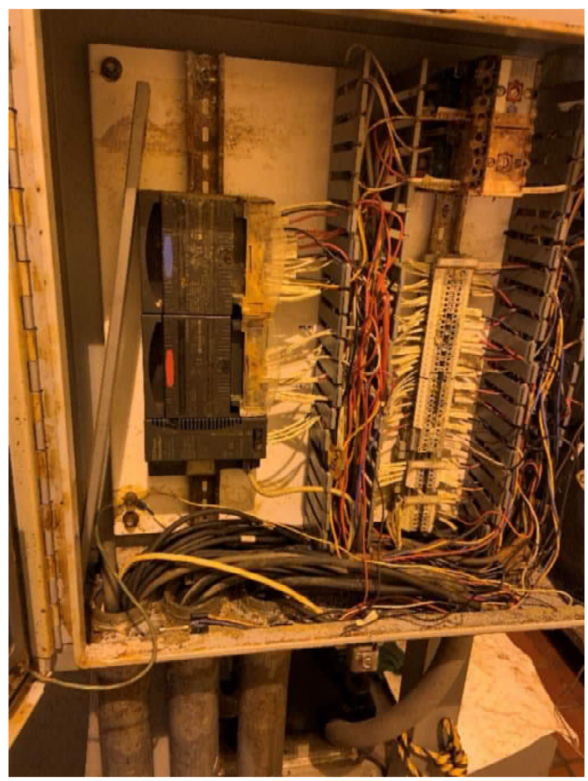


Photo 5-5 Caonillas 1 Governor PLC (flooded – replace)

Recommendations: The flooded governor PLCs will have to be replaced. Consider also upgrading the unit and plant Atlas-II controllers and operator workstation located in the control area upstairs.

Upgrading the unit and plant controls at the same time will avoid having to integrate new governors into the existing unit controllers. The governor functionality can be incorporated into the unit controller. The new governor can interface with the SCADA system and allow remote operation from Dos Bocas.

5.2.2 Potential for Remote Control

There is a functioning microwave communication to the plant providing remote monitoring and control from Dos Bocas.

The Caonillas 1 plant is fully automated and can be remotely controlled from the Dos Bocas hydroelectric facility. In addition to load control, the units can be started and stopped remotely from Dos Bocas. There is a computer with graphic displays of the Caonillas 1 facility used for remote monitoring and unit control in the Dos Bocas main control room. Because the units are already remotely controlled from Dos Bocas, remote operation could also be extended to the ECC.

If the ECC uses the network interface at Dos Bocas to monitor the Caonillas 1 units, this SCADA system could be modified to provide remote ECC control. If there is communication directly between the Caonillas 1 facility and the ECC, the SCADA system at Caonillas 1 could be modified to provide remote ECC control. To have the same functionality at the ECC as was available at Dos Bocas, the flooded governor controls need to be replaced and the SCADA system modified.

5.3 CAONILLAS 2 HYDROELECTRIC PLANT

The Caonillas 2 powerhouse was constructed in 1950 and consists of one vertical 4 MW Francis turbine. The Caonillas 2 plant was flooded during Hurricane Georges in 1998 and the unit is not operational. In general, all the mechanical systems for the turbines, and balance of plant mechanical systems are in need of replacement to bring the system back to operational condition.

5.3.1 Potential for Automated Frequency Response

There is a Woodward Type HR mechanical governor that is the original equipment.

Photo 5-6 Caonillas 2 Mechanical Governor

Recommendations: Replace the mechanical governor with a modern digital governor which will include an automatic frequency response. The hydraulic system will also need to be replaced as part of the digital conversion.

5.3.2 Potential for Remote Control

There are no operational fiber optic or microwave communication links to this facility. There is an HSQ Technology 2500 Series RTU that is out of date and has a circuit board removed. The 2500 Series RTU processor was phased out of service (no longer sold new) by HSQ in 2005, therefore the SCADA system is over 16 years old.

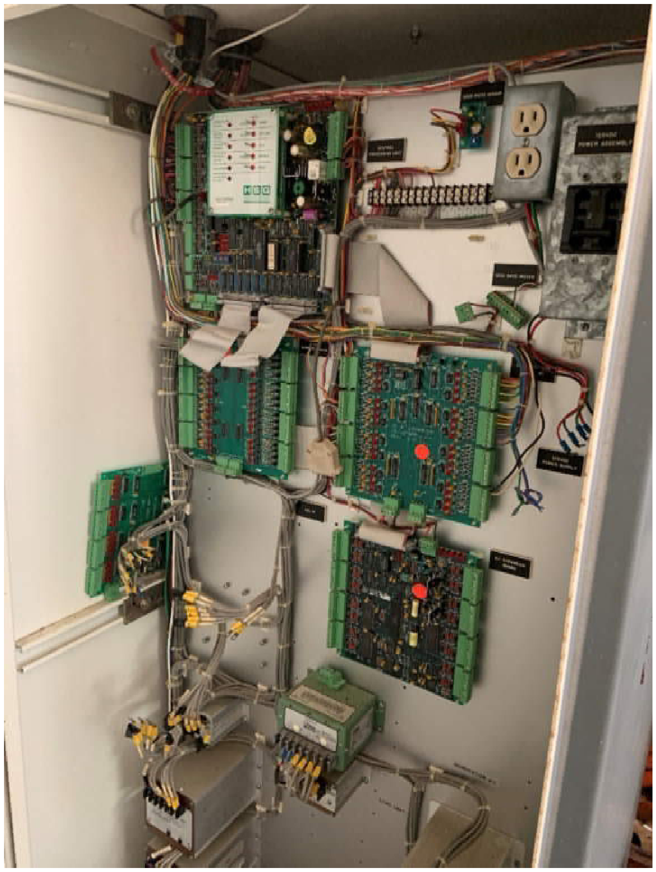


Photo 5-7 Caonillas 2 SCADA System

The unit was manually operated using controls on the original switchgear lineup. The switchgear can be replaced with a smaller lineup.

New automated unit controls, a modern static excitation system and digital governor will provide the required interface for full remote control from the ECC. The SCADA system will need to be updated and communication re-established between the facility and the ECC to support remote control.

6.0 Toro Negro System

The Toro Negro Hydroelectric System consists of two plant developments:

- Toro Negro 1
- Toro Negro 2

6.1 TORO NEGRO 1 HYDROELECTRIC PLANT

The Toro Negro 1 powerhouse was constructed in 1929 and contains three 1.44 MW Pelton type turbine generators (Units 1-1, 1 2, & 1-3) and one 4.3 MW Pelton type turbine generator (Unit 1-4); which was added later in 1937. At the time of the visit, Units 1-1 and 1-2 were online.

6.1.1 Potential for Automated Frequency Response

The Units 1-1, 1-2 and 1-3 turbines have manual needle operators and deflector control. The three smaller units are equipped with flywheels to increase momentum ride through and improve governing stability. The Units 1-1, 1-2 and 1-3 controllers are a mechanical hydraulic type manufactured by Woodward Governor Company. Speed sensing is via a belt riding over the turbine shaft. The needles are controlled manually using a handwheel at the unit to adjust unit speed, frequency and load. Units 1-1, 1-2 and 1-3 do not have automatic frequency response capability. In order to get automatic frequency response, there would need to be a digital conversion of the mechanical equipment.

Unit 1-4 has a Woodward Type LR mechanical governor. The unit speed can be controlled locally from the main control benchboard. The mechanical governor will respond automatically to frequency deviations.

Photo 6-1 Toro Negro 1 Units 1-3 Mechanical Positioner

Photo 6-2 Toro Negro 1 Unit 1-4 Mechanical Governor

Recommendations: To modernize the facility and add automatic frequency response to Units 1-1, 1-2 and 1-3, the manual positioners can be replaced with digital governors providing local or remote control. The digital governors will provide needle and deflector control. The belt driven speed sensing can be replaced with modern speed instrumentation utilizing a toothed gear and speed probes.

If the manual positioners are upgraded to digital governors, this would also be a good opportunity to convert the Unit 1-4 mechanical governor to digital.

6.1.2 Potential for Remote Control

There is a functioning microwave communication to the plant allowing ECC monitoring of this facility. There is a modern Harris RTU providing remote monitoring of the facility from the ECC. There is no remote control of the generating units from the ECC.

The generating units are manually controlled locally. In addition to manual control of the load described above, the voltage is also controlled by manually closing field breakers and adjusting rheostats.

In order to provide ECC remote startup, shutdown control of the units, the manual startup and shutdown sequences including synchronization would need to be automated. Modern control systems use programmable logic controllers (PLCs) or other processors to provide the unit startup / shutdown sequencing, synchronization and load control. The control systems include input/output modules to interface the instrumentation and equipment. The control system includes an operator workstation with graphic screens for unit operation, monitoring and alarm management. The manual needle and deflector operators would need to be replaced with digital governors to support automatic sequencing and remote load control. The existing voltage regulators and field breakers would also need to be replaced with modern static excitation equipment to support automatic sequencing and remote voltage control. The existing Harris RTU would need to be modified to add remote control.

The Aceitunas forebay is upstream of the Toro Negro 1 facility and has two intakes gates. The Aceitunas forebay formerly was level controlled from the powerhouse, but communications were lost after Hurricane Maria. Now the local operators watch for overflow coming down a channel and watch the penstock pressure to verify that the water level is adequate for operation. The intake gates are manually controlled locally at the forebay. Restoring communication and remote control of the intake gates from the Toro Negro 1 facility can reduce spilling water and losing generation.

The intake to the Matrullas canal (outlet from the Matrullas reservoir) has a gate which was automatically controlled from Toro Negro 1 before Hurricane Maria. However, the communication system was damaged during Hurricane Maria and now the gate is manually opened and closed by an operator locally using a phone to communicate with the personnel at the powerhouse for opening and closing of the gate.

6.2 TORO NEGRO 2 HYDROELECTRIC PLANT

The Toro Negro 2 powerhouse was constructed in 1937 and contains one single nozzle over-hung 2.0 MW Pelton turbine generator. The unit is currently not operational as the penstock needs repair. PREPA indicated that the penstock repairs should be completed by March 2021 and the facility will be back in operation by April-May 2021.

6.2.1 Potential for Automated Frequency Response

The unit has the original mechanical Woodward governor. Operation of the governor is reported to be good with steady control of the unit. The unit speed can be controlled locally from the main control panel. If the governor is tuned and working properly, it should provide automatic response to frequency changes.

Photo 6-3 Toro Negro 2 Mechanical Governor

Recommendations: To modernize the facility, the mechanical governor can be converted to a digital governor with an electronic controller and touchscreen graphic OIT.

6.2.2 Potential for Remote Control

There is a functioning microwave communication to the plant providing metering data to the ECC. The ECC monitors metering data from the plant and does not have any remote control of the unit.

The unit is manually controlled locally at the facility.

In order to provide ECC remote startup, shutdown control of the units, the manual startup and shutdown sequences including synchronization would need to be automated. The mechanical governor would need to be replaced with a digital governor to support automatic sequencing and remote load control. The manual rheostat controls would also need to be replaced with modern static excitation equipment to support automatic sequencing, automatic voltage regulation, and remote voltage control. The existing SCADA RTU would need to be modified or replaced to add remote control.

7.0 Garzas System

The Garzas Hydroelectric System consists of two plant developments:

- Garzas 1
- Garzas 2

7.1 GARZAS 1 HYDROELECTRIC PLANT

The Garzas 1 power constructed in 1941 and contains two single-nozzle, over-hung 3.6 MW Pelton type turbines, each driving a single generator. At the time of the visit, both units were online.

7.1.1 Potential for Automated Frequency Response

The units have the original Woodward Type LR mechanical governors. It was noted that the governors have some mechanical issues and need rebuilt or maintenance annually. The unit can be controlled locally at the main control benchboard. If the governor is tuned and working properly, it should provide automatic response to frequency changes.

Photo 7-1 Garzas 1 Woodward Type LR Mechanical Governor

Recommendations: To modernize the facility, the mechanical governors can be converted to digital governors with an electronic controller and touchscreen graphic OIT.

7.1.2 Potential for Remote Control

The microwave system is currently down. Previously there was an RTU at this facility for remote monitoring, it has been removed. When the microwave and RTU were functioning the ECC remotely monitored metering values, there was no remote control for the units.

There used to be a second transmission line in service to the Garzas 1 plant connecting power and communications over to the Garzas 2 plant. This line allowed the Garzas 2 unit to be controlled from the Garzas 1 powerhouse, improving coordination between the two facilities. This second transmission line is not in service.

The Garzas 1 units are manually controlled locally at the plant from the main control benchboard and relay / metering panel.

In order to provide ECC remote startup, shutdown control of the units, the manual startup and shutdown sequences including synchronization would need to be automated. The mechanical governors would need to be replaced with digital governors to support automatic sequencing and remote load control. The manual rheostat controls would also need to be replaced with modern static excitation equipment to support automatic sequencing and remote voltage control. The microwave system would need to be repaired and a new SCADA system installed at the plant to support remote ECC operation.

7.2 GARZAS 2 HYDROELECTRIC PLANT

The Garzas 2 powerhouse was constructed in 1941 and contains one single-nozzle, double over-hung 5.0 MW Pelton type turbine pair, driving a single generator between the turbines. The 38 KV, transmission line 1100 to the plant is down due to Hurricane Maria and needs extensive repairs. PREPA will schedule the work to get the units operating again in coordination with the transmission line return to service.

7.2.1 Potential for Automated Frequency Response

The Woodward Type LHR mechanical governor operates a common deflector shaft connected to both turbines. The governor is reported to have good steady control for the unit. If the governor is tuned and working properly, it should provide automatic response to frequency changes.

Photo 7-2 Garzas 2 Woodward Type LHR Mechanical Governor

Recommendations: To modernize the facility, the mechanical governor can be converted to a digital governor with an electronic controller and touchscreen graphic OIT.

7.2.2 Potential for Remote Control

The microwave system needs repaired, currently there is no communication to this facility from ECC. There is an outdated HSQ Technology 2500 Series RTU in the powerhouse for remote monitoring of the facility. The ECC does not have any remote control of the unit.

The transmission line has failed so they can't run the unit. There used to be a transmission line in service connecting power and communications between the Garzas 1 and the Garzas 2 plants. This line allowed the Garzas 2 unit to be controlled from the Garzas 1 powerhouse.

The generating unit is manually controlled locally from the main control panel.

In order to provide ECC remote startup, shutdown control of the units, the manual startup and shutdown sequences including synchronization would need to be automated. The mechanical governor would need to be replaced with digital governors to support automatic sequencing and remote load control. The outdated voltage regulator rheostat would also need to be replaced with modern static excitation equipment to support automatic sequencing and remote voltage control. The microwave system would need to be repaired or consider running fiber with the transmission line when it is repaired to restore the remote communication link. The existing SCADA RTU would need to be modified or replaced to support remote ECC operation.

8.0 Yauco System

The Yauco Hydroelectric System consists of two plant developments:

- Yauco 1
- Yauco 2

8.1 YAUCO 1 HYDROELECTRIC PLANT

The Yauco 1 powerhouse was constructed in 1953 and contains a single 25 MW, vertical six jet Pelton type turbine generator unit. At the time of the site visit, the unit was dismantled. It is reported that the unit has not operated since 2014 due to vibration issues.

8.1.1 Potential for Automated Frequency Response

The governor is a mechanical-hydraulic cabinet actuator type supplied by Woodward Governor Company. The governor operates the jet deflectors in unison with the needles slowly following the movement of the deflectors.

When Pelton turbines are required to operate over a wide load range, it is common for the governor to provide automatic change between one-needle up to six-needle operation. This maintains higher efficiency over the load range compared to a constant six-needle operation. This operation is not provided by the existing governor. Since each needle has its own position controller, a conversion to two, four or six-needle operation would be relatively straight forward.

If the governor is tuned and working properly, it should provide automatic response to frequency changes.

Photo 8-1 Yauco 1 Mechanical Governor Cabinet

Recommendations: To modernize the facility and provide automatic two, four and six needle operation, the mechanical governor can be converted to a digital governor with an electronic controller and touchscreen graphic operator interface OITs. Including needle sequencing as part of the governor control will improve the unit efficiency.

8.1.2 Potential for Remote Control

The microwave at this plant is not in service.

There is an outdated HSQ Technology 2500 Series RTU which has lost some functionality for remote monitoring and control. The ECC had the ability to remotely adjust load and voltage, this functionality needs repaired. The ECC used to be able to remotely start and stop the unit, this capability is no longer working and needs to be repaired. The ECC used to be able to remotely start the emergency generator, this functionality is no longer working. Some of the RTU circuit boards have failed.

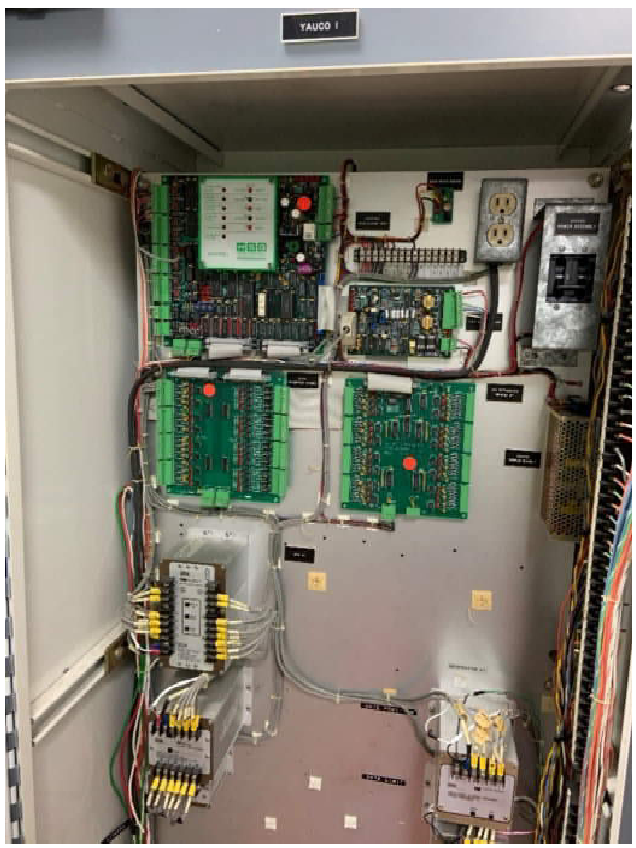


Photo 8-2 Yauco 1 SCADA RTU – HSQ 2500

The plant is operated by start/stop operations, voltage and power control performed locally at the walk-in control panel in the powerhouse control room.

These units had remote operation previously. Communication between the plant and the ECC can be restored. The plant SCADA system can be repaired or upgraded restoring the previous remote control functionality.

8.2 YAUCO 2 HYDROELECTRIC PLANT

The Yauco 2 powerhouse was constructed in 1953 and contains two 5 MW vertical Francis type turbine generator units. At the time of the visit, both units were operating in synchronous mode.

8.2.1 Potential for Automated Frequency Response

Each unit has a gate shaft Type HR mechanical governor manufactured by Woodward Governor Company. It is reported that the governors respond well. The wicket gates can be controlled locally from the main control panel. Once online, the unit load can be controlled remotely from ECC. If the governor is tuned and working properly, it should provide automatic response to frequency changes.

Photo 8-3 Yauco 2 Woodward Type HR Mechanical Governor

Recommendations: To modernize the facility, the mechanical governors can be converted to digital governors with electronic controllers and touchscreen graphic OITs.

8.2.2 Potential for Remote Control

There is a functioning microwave communication to the plant allowing ECC remote monitoring and load / voltage control.

The plant has a modern Harris RTU panel and an outdated HSQ Technology 2500 Series RTU panel.

The units are run in synchronous condense mode allowing ECC load and voltage control. The units are manually put online and shut down locally at the walk-in control panel located in the powerhouse control room. In order to expand ECC operation to include remote startup, shutdown control of the units, the manual startup / shutdown sequences including synchronization would need to be automated.

9.0 Río Blanco System

The Río Blanco Hydroelectric System one consists of one plant development, the Río Blanco hydroelectric facility.

9.1 RÍO BLANCO HYDROELECTRIC PLANT

The Río Blanco powerhouse was constructed in 1930 and contains two 3.125 MVA horizontal Pelton type turbine generator units. At the time of the visit, the units were not operational because of a penstock failure that needs to be repaired.

9.1.1 Potential for Automated Frequency Response

The governor is a mechanical type deriving its operating power from a leather belt on the turbine/generator shaft. No oil pressure set is required for turbine needle and deflector operation. Speed sensing is via another leather belt on the shaft. The governor has only one electrical connection, a raise-lower motor to run a valve which opens and closes the needle valve. The units are equipped with flywheels to increase momentum ride through and improve governing stability. There is a Speed Control Raise-Lower switch on the main control panel for local operation. If the governor is tuned and working properly, it should provide automatic response to frequency changes.

Photo 9-1 Río Blanco Flywheel, Belt Connections

Photo 9-2 Río Blanco Mechanical Governor

Recommendations: To modernize the facility and remove personnel exposure to the moving leather belts, the mechanical governors can be converted to digital governors with electronic controllers and touchscreen graphic OITs.

9.1.2 Potential for Remote Control

There is a functioning fiber optic network to the plant allowing remote monitoring at the ECC.

There is an older Harris RTU providing the ECC data for remote monitoring. The ECC does not have remote control at this facility.

The units are controlled manually from the main control panel in the powerhouse control room. There is a manually adjusted rheostat and mechanical voltage regulator for local voltage control. The generator circuit breakers are manually closed from the front of the main control panel using a large lever connected to the oil circuit breaker compartment behind the panel.

Photo 9-3 Río Blanco Circuit Breaker Lever and Voltage Regulators

In order to provide ECC remote startup, shutdown control of the units, the manual startup and shutdown sequences including synchronization would need to be automated. The mechanical governors would need to be replaced with digital governors to support automatic sequencing and remote load control. The outdated voltage regulator rheostat would also need to be replaced with modern static excitation equipment to support automatic sequencing and remote voltage control. The manually operated, oil type generator circuit breakers would need to be replaced. The existing SCADA RTU would need to be modified or replaced to support remote ECC operation.

Previously the inlet valve located above the powerhouse was hardwire controlled from the powerhouse, this is no longer functional. There are plans to add a microwave between the inlet valve and the powerhouse to allow valve control from the powerhouse.

Exhibit B

Task 600-Economic Feasibility Analysis Report dated June 3, 2021

FINAL

TASK 600 – ECONOMIC FEASIBILITY ANALYSIS REPORT

BLACK & VEATCH PROJECT NO. 407635.0600

Puerto Rico Electric Power Authority

3 JUNE 2021

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1 Executive Summary

The report presented herein evaluates the economic feasibility of rehabilitating the Puerto Rico Electric Power Authority's (PREPA) hydroelectric generating facilities (Hydroelectric Facilities).

Black & Veatch completed a comprehensive economic feasibility analysis that determined two potential rehabilitation portfolio options for 10 Hydro Facilities owned and operated by PREPA. There are multiple factors to consider in the technical feasibility of refurbishing these facilities; however, determining the true economic feasibility of rehabilitating all facilities under consideration is critical.

The improvements proposed, in some cases, affect the production potential, increased reliability, and synergies in the staffing and operations of the systems evaluated. For this reason, Black & Veatch has analyzed the impact of improvements for each facility individually and as a collective portfolio of systems to determine the feasibility of rehabilitating and operating these Hydroelectric Facilities.

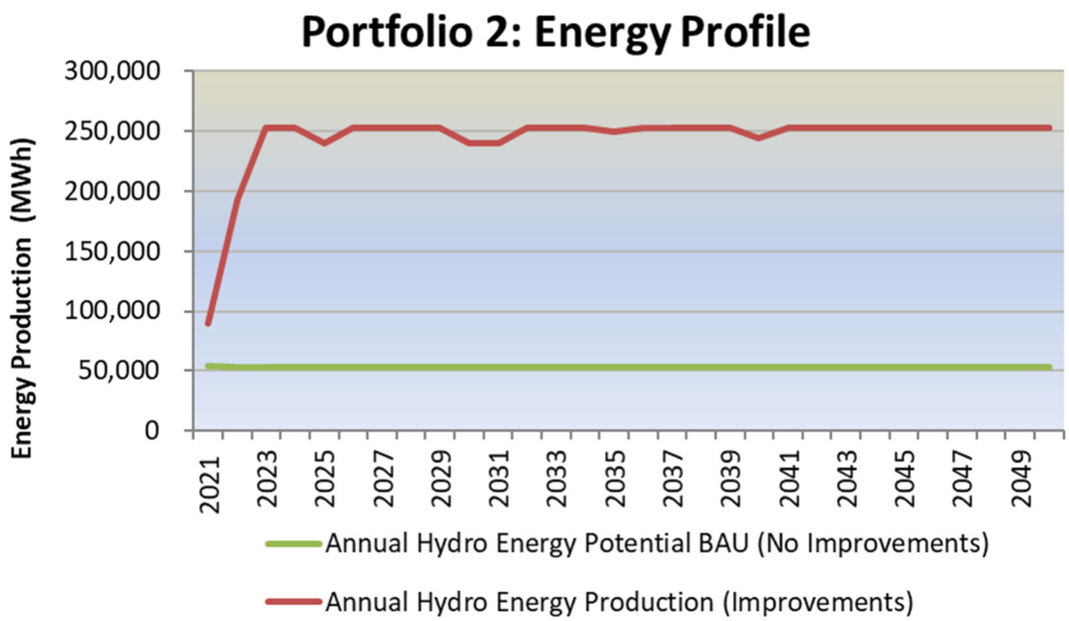
After considering multiple scenarios and improvement configurations, two portfolios of improvements were analyzed in-depth**:**

- Portfolio 1 - Consists of projects producing the Highest Net Present Value (NPV) Improvement for <u>each Hydroelectric System</u>; and
- Portfolio 2 – Represents the projects producing the Best Implementable per Technical, Geographical, and Reasonable factors <u>for each Hydroelectric System</u>.

Under Portfolio 2, the collection of projects proposed for each Hydro System inherently include technical, geographic, and practical considerations for implementation. Under Portfolio 1, the projects are not bundled with an eye towards implementation matters. Each portfolio includes technical, geographic, and practical considerations. Each portfolio contains specific improvements or derivations of improvements to rehabilitate the selected Hydroelectric Facility.

As shown in Figure 1-1, currently, the energy generated from the existing in-service Hydroelectric Facilities produces approximately 50,000 megawatt-hours (MWh) (green line) annually, representing about 0.3% of PREPA's annual power production. After implementing either of the two portfolios, hydroelectric energy production would grow to about 250,000 MWh. Figure 1-1 presents a comparison of the energy produced by the Hydroelectric Facilities under a Business as Usual (BAU) case and the energy produced after the implementation of the Portfolio 2 improvements, the recommended portfolio of improvements.

Figure 1-1 Comparison of PREPA's Energy Requirement and Energy Produced by the Hydro Facilities

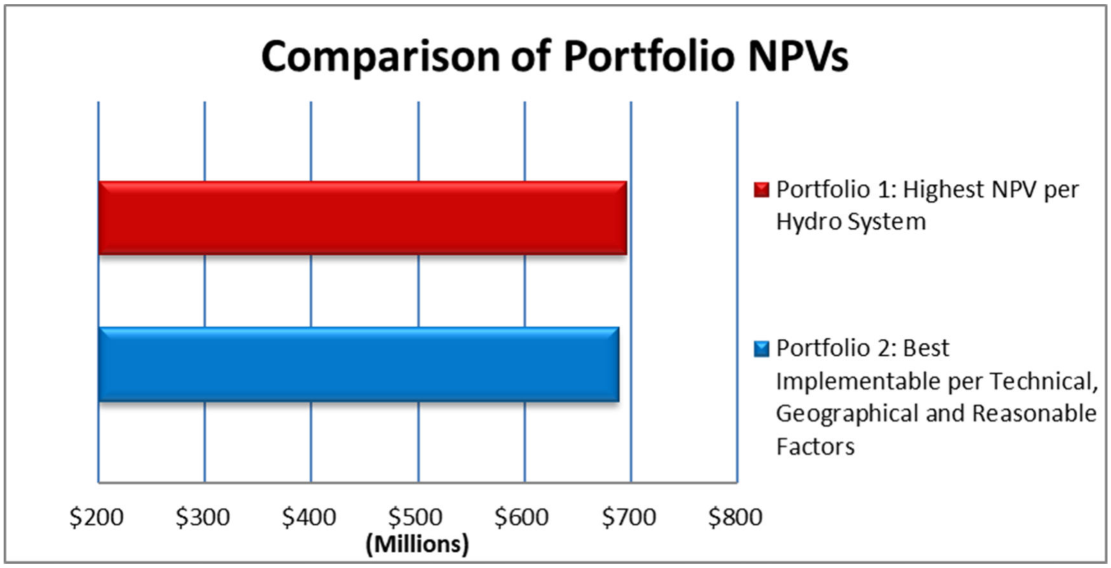


With recommended improvements identified in Portfolios 1 and 2, PREPA could achieve a five-fold increase in hydroelectric power production by implementing one of the portfolios of improvements outlined within the Report.

Black & Veatch has identified economically feasible rehabilitation projects at each facility and recommends that PREPA implements Portfolio 2. Portfolio 2 represents the highest NPV Portfolio of Improvements for all Hydroelectric Systems, given certain technical, geographic, and practical considerations. The actual improvements associated with Portfolio 2 and the other portfolios are discussed in Sections 5 & 6 of this Report. The collective improvements from Portfolio 2 do not represent the greatest economic impact from all the portfolios evaluated; however, it represents an approach that rehabilitates all the Hydroelectric Facilities analyzed herein and achieves improved reliability and operations of the Hydroelectric Facilities.

Portfolio 2 results in a positive annual cash flow of $4.7 million in 2021, and this annual result will increase to $42.6 million by the end of 2050. As a result, the calculated NPV is $687.5 million over the 30 year study period (2021 - 2050). As detailed in the illustration below, Portfolios 1 produces an NPV total of $695.8 million. The total capital to be invested for Portfolio 2 is $166.7 million and $163.3 million for Portfolio 1 over the study period.

Figure 1-2 Comparison of the Portfolio NPV Results



Both Portfolios produce positive and increasing cash flows over the 30-year Study Period. While the NPV values outlined are positive and significant over the 30-year Study Period and highlight an opportunity for PREPA to achieve incremental energy production cost savings, consideration must be given to the technical and geographic requirements along with the practicality of implementing PREPA's next increment of hydroelectric power generation.

This evaluation was prepared for PREPA and is based on information that was provided by PREPA and not within the control of Black & Veatch. Black & Veatch has not been requested to make an independent analysis, to verify the information provided to us, or to render an independent judgment of the validity of the information provided by others. As such, while Black & Veatch did not identify any inconsistencies with the information provided, Black & Veatch cannot, and does not, guarantee the accuracy thereof to the extent that such information, data, or opinions were based on information provided by others.

In conducting our analyses and in forming an opinion of the projection of future financial operations summarized herein, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. Such assumptions and methodologies are summarized in this report and are believed to be appropriate for the purpose for which they are used. While Black & Veatch believes that the assumptions are reasonable and the projection methodology valid, actual results may differ materially from those projected, as influenced by the conditions, events, and circumstances that actually occur.

2 Project Background

PREPA engaged Black & Veatch to conduct a feasibility study of ten hydroelectric facilities. The study provides an overview of the current electric generating capacity of the Hydroelectric Facilities and evaluates the potential to increase electric generation by implementing certain improvements to the Hydroelectric Facilities evaluated.

As such, PREPA requires a detailed assessment of the Hydroelectric Facilities. Task 600, as defined herein, is a detailed economic feasibility analysis that considers the economic impact and specific costs and benefits of implementing specific Hydroelectric Facilities' improvement projects. This objective is achieved by utilizing an approach that incorporates understood technical requirements with specific economic and financial guidelines.

As a part of this task, Black & Veatch considered several improvements for each of the 10 Hydroelectric Facilities. Provided is a list of the ten Hydroelectric Facilities evaluated and a designation of "active" for facilities that are in-service and "inactive" for facilities that are out of service:

- Toro Negro 1 (active)
- Toro Negro 2 (inactive, ready for testing)
- Garzas 1 (active)
- Garzas 2 (inactive)
- Caonillas 1(inactive)
- Caonillas 2 (inactive)
- Dos Bocas (active)
- Rio Blanco (inactive)
- Yauco 1 (inactive)
- Yauco 2 (active)

Black & Veatch prepared an economic feasibility evaluation that included the following components:

2.1 EVALUATION OF RECOMMENDED IMPROVEMENTS

Black & Veatch has prepared a projection of the costs and benefits of the proposed improvements necessary to restore the 10 Hydroelectric Facilities evaluated. In the analysis, we have included improvements for the powerhouse, electrical and mechanical equipment, automation for some facilities, and other system-related elements such as pipelines, canals, and penstocks. Section 5 of this Report provides the details related to the nature of the improvements evaluated herein.

2.2 FINANCIAL FEASIBILITY EVALUATION

Black & Veatch determined PREPA's long-term cost to operate each hydropower facility after implementing the recommended improvements identified in Task 200, Assessment of Existing Hydroelectric Facilities. In addition, the fixed cost and unit cost of power per kilowatt-hour (kWh) was projected to identify potential energy cost-savings to PREPA compared to its existing unit cost of power generation of their overall system. Finally, the improvements on net cash flow were evaluated to determine the financial impact due to increased power production.

2.2.1 Capacity and Energy Output of Hydroelectric Facilities

Based on the data gathered as a part of Task 100 through Task 500 of this project, the historical generating capacity and the annual energy output of all Hydroelectric Facilities were determined over the last three years. Black & Veatch determined the aggregate energy production of all powerhouses, the unit cost of energy, and the total cost to operate each hydroelectric facility. Over the last three years, the cost to operate each facility included operations (with and without automation) and maintenance, debt service, and annual capital additions recommended under Task 200. After projecting the annual energy output and the annual cost of operations, Black & Veatch incorporated the recommended improvements identified for each hydroelectric facility in Task 200 and developed a thirty-year financial forecast outlining the cost to operate each facility. In collaboration with PREPA management staff, the project team identified specific assumptions related to financing the recommended improvements. As a result of this financial evaluation, Black & Veatch projected PREPA's annual fixed and unit cost of hydroelectric power on a portfolio basis.

2.2.2 PREPA Cost of Power Comparison

Black & Veatch developed a cost-of-power comparison of PREPA's existing cost of power generation with the cost of the power generation for the restored and working Hydroelectric Facilities. Annual positive operating balances (revenues less costs) represent opportunities for PREPA to achieve cost savings with the implementation of PREPA's next increment of Hydroelectric power. A cost-benefit analysis was performed to determine the economic feasibility of implementing the proposed improvements at each facility evaluated. It is understood that certain PREPA transmission and distribution-related costs, such as wheeling and delivery of the power generation, may need to be considered to understand the cost savings that PREPA may achieve.

Black & Veatch views the determination of the feasibility of Hydroelectric power generation as the main objective of Task 600.

3 Economic Feasibility Analysis Process

In accordance with the scope of services outline for Task 600, Black & Veatch performed an economic feasibility analysis to determine the costs and associated benefits of implementing specific improvements for the Hydroelectric Facilities outlined in this report. The approach utilized and the economic ranking methods are described herein. Figure 3-1 below provides a flow diagram of the economic feasibility analysis approach.

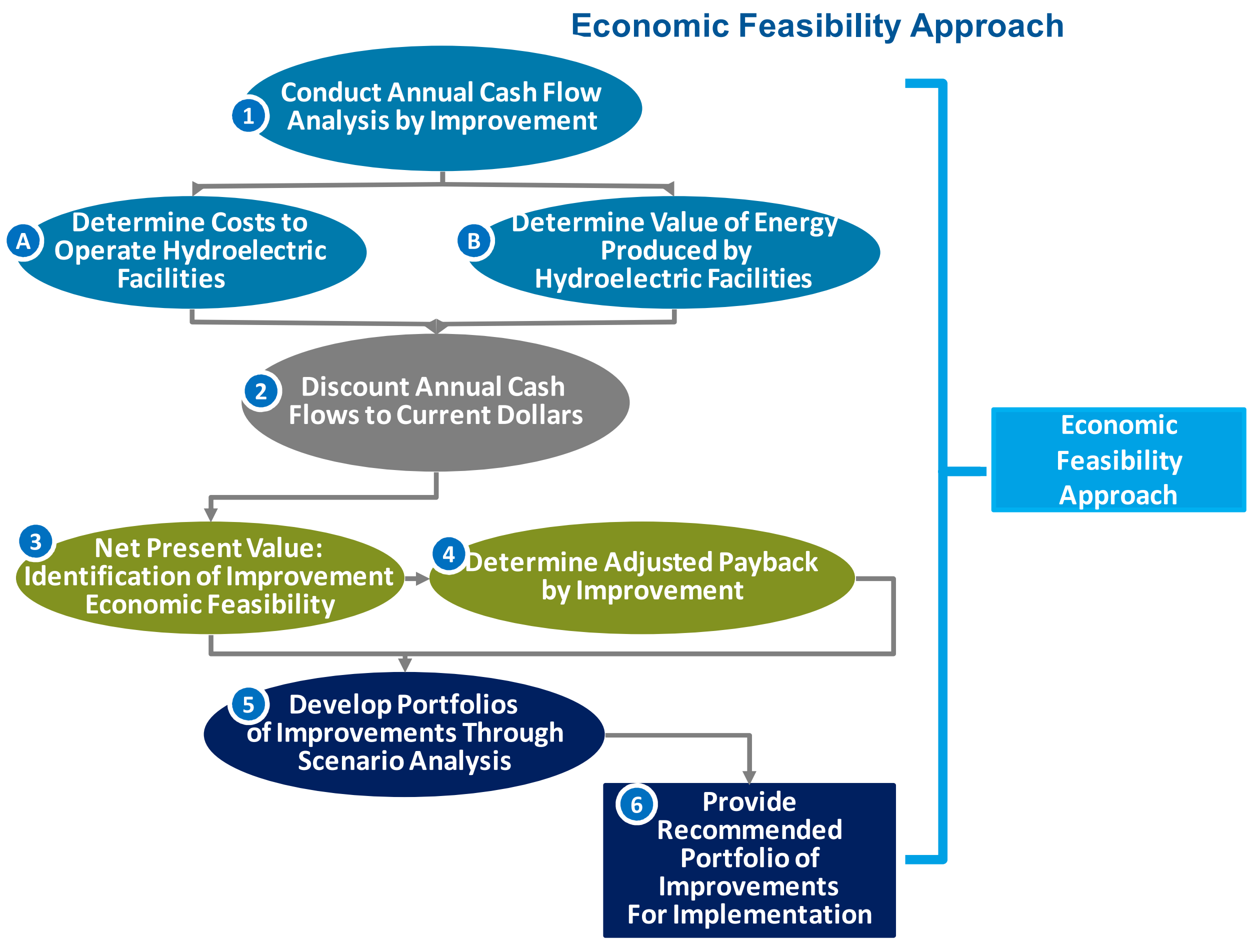


Figure 3-1 Economic Feasibility Approach Flow Diagram

3.1 ECONOMIC FEASIBILITY APPROACH

Below is a brief description of each step associated with the economic feasibility approach outlined in Figure 3-1.

1. **Conduct Annual Cash Flow Analysis by Improvement**: Determine the cost to implement and operate the analyzed Hydroelectric Facilities based on the potential improvements developed by Black & Veatch. In addition, assess the value of the incremental energy produced and compare this value to the facility's cost after the recommended improvement to determine potential cost savings.

2. **Discount Annual Cash Flows to Current Dollars**: Discount the cash flow associated with the proposed improvements over the thirty-year forecast period to current-day dollars based on the existing cost of borrowing. After this analysis, the facility NPV is determined based on the recommended improvement. A positive NPV indicates a potential for cost savings.

3. **Net Present Value (NPV), Identification of Improvement Economic Feasibility**: Perform a comparison of all the facilities' calculated NPV to determine the most economically feasible improvement recommended.

4. **Determine the Adjusted Payback Period by Improvement**: Determine the ability of each facility to pay back the capital-related cost to implement the improvement based on the cost savings calculated over the 30-year forecast period.

5. **Determine Portfolios of Improvement through Scenario Analysis**: Determine specific portfolios of improvements based on specific technical, geographic, and reasonable considerations.

6. **Provide Recommended Portfolio of Improvement for Implementation**: Recommend the portfolio of improvements deemed reasonable for implementation.

3.2 ECONOMIC/FINANCIAL FEASIBILITY APPROACH

Black & Veatch performed the economic feasibility analyses and developed opinions thereof, utilizing a discounted cash flow methodology (DCF). DCF is a commonly accepted methodology in performing financial analyses. A DCF analysis discounts the value of future cash flows in current dollars, recognizing the time value of money that a dollar today is worth more than a dollar in the future. A discount rate of 6.15% was used in the DCF calculation presented below:

DCF = (Cash Flow 1)/ ((1+Discount Rate)^1) + (CF 2)/((1+ DR)^2) + (CF 3)/((1+DR)^3) + ...

The DCF analysis identifies the value of future cash flows generated by the Hydroelectric Facilities after implementing the evaluated improvements. Cash flow is defined as the total available cash generated from operations or positive cash flows (revenue from the sale of energy or energy cost savings) less the cost of implementing the improvement project and operating the facility thereafter. Upon discounting all the future projected cash flows, a value for this cash flow is determined called the Net Present Value (NPV).

Black & Veatch performed this analysis for each evaluated improvement at each Hydroelectric Facility over a 30-year study period and selected improvements to develop portfolios of improvements. The results of this analysis are detailed in Sections 6 and 7 of this Report.

3.2.1 Revenue/Energy Cost Savings

After implementing the improvements, the revenue or energy cost-savings from the Hydroelectric Facilities represents cash inflow or cost avoidance in the DCF analysis. Electricity generated by the Hydroelectric Facilities is assumed to be contributed to the power grid and sold to customers at existing electric rates as reported by PREPA.

Electricity generated at each Hydroelectric facility is one of the components necessary to compute the potential revenue/energy cost savings as a part of the cash flow analysis. The other component is the value or unit cost of energy produced by PREPA based on its existing fleet of generating resources. The difference in the unit cost of Hydroelectric power and PREPA's aggregate unit cost of power establishes the basis to determine the economic feasibility of restoring the respective Hydroelectric Facilities.

3.2.2 Costs to Operate

To determine the costs to operate the Hydroelectric Facilities, Black & Veatch evaluated the following information:

- Historical operating cost information for the active and inactive Hydroelectric Facilities;
- Projected capital costs and the financing charges associated with implementing the improvements;
- Projected potential incremental operation and maintenance (O&M) costs associated with the improvements; and
- Projected the renewal and replacement costs to maintain the capital investment properly.

Annual operating costs for purposes of this analysis include the following:

- Existing O&M costs associated with the current operation of the facility;
- Incremental O&M costs associated with the projected operation at each facility;
- New debt service and the requirements with the financing of the improvements;
- 0% Cash financed capital costs associated with the improvements; and
- Cash financed Renewal & Replacement costs and annual upkeep associated with the improvements.

Black & Veatch calculated the total costs to operate each facility and implemented the improvements over a 30-year forecast period. The net result of annual revenues less total annual costs to operate provides an annual operating balance for each Hydroelectric Facility.

3.3 IMPROVEMENT RANKING METHODS

The primary method of evaluating the economic feasibility of an improvement is to demonstrate the financial feasibility of the improvements on the Hydroelectric Facilities evaluated. As an industry-wide accepted method, Black & Veatch's primary ranking method for the analysis detailed herein is the NPV.

Along with the NPV analyses, Black & Veatch utilized several other considerations in determining how the improvements would be ranked from an economic perspective. While the NPV calculation provides the primary method to evaluate the improvements, there are several other components to our economic feasibility approach. Listed below is a summary of the additional ranking methods utilized herein:

- Adjusted Payback Period
- Energy Output

- Capacity Factor
- Capital Cost
- Unit Cost of Energy

3.3.1 Net Present Value

NPV is the process of returning future cash flow values to current dollars to determine the current worth of those future cash flows. The NPV serves as the primary decision-making metric for financial analyses of this nature. A positive NPV indicates that the benefits of the improvements or portfolio of improvements outweigh the costs to implement and sustain these improvements over the 30-year study period. Conversely, a negative NPV indicates that the improvement will provide a negative future cash flow stream because the costs to implement and operate are greater than the economic benefits achieved. From an economic perspective, an improvement that generates a higher NPV should be prioritized to maximize the economic and financial benefits of that improvement. Still, consideration must be given to other evident technical, regulatory, geographic, and other reasonable considerations.

3.3.2 Adjusted Payback Period

In engineering terms, the simple payback period is a commonly utilized metric to determine how quickly an improvement or project will "pay for itself." It is calculated by simply taking the capital cost of the improvement divided by the annual or monthly free cash flows generated from the improvements to calculate how many years/months include the payback period. Black & Veatch has utilized the general concept of this idea, but implemented adjustments for the time value of money, which is the primary limitation of the simple payback calculation.

The adjusted payback period is calculated by taking the capital cost of the improvement and dividing it by the average annual discounted cash flow from the same improvement. The calculation for the adjusted payback period is the following:

Adjusted Payback Period = Total Capital Cost / [Calculated NPV/Years in Projection Period]

Average annual discounted cash flow is utilized in this analysis because, in some cases, the payoff period is greater than the thirty-year study period. Improvements with a negative NPV will not have a calculated adjusted payback period because the negative NPV will not provide sufficient economic benefits to outweigh its associated costs.

3.3.3 Other Ranking Metrics

Other financial and operational metrics are shown to provide additional perspectives on the economic impact of the recommended improvements under consideration. Provided below is a list of additional metrics utilized to evaluate the improvements:

- Annual Energy Output (in MWh)
- Annual Capacity Factor (Output Utilization)
- Capital Cost in $/kW
- Unit Cost of Energy in $/kWh

4 Description of Existing Hydroelectric System

This section presents an evaluation of the facility conditions, existing capacity, and the existing annual generation of the ten Hydroelectric facilities evaluated.

The existing and potential installed capacity and the existing and potential average annual generation of the facilities were determined from site visits performed by Black & Veatch in February 2021 and historical Hydroelectric Facilities' performance information provided by PREPA. Table 4-1 summarizes the existing generation capacity of each plant, the current status of operation, and the identified improvement needs for each facility.

Table 4-1 Summary of the Facilities' Status, Existing Capacity, and Improvement Needs

FACILITY	STATUS	EXISTING CAPACITY (MW)**	IMPROVEMENT NEEDS
Yauco 1	Inactive	20.0	Mechanical, electrical equipment improvements Dredging Modify Yahuecas and Prieto to pass sediment Automation
Yauco 2	Active	8.0	Mechanical, electrical equipment improvements Dredging Modify Yahuecas and Prieto to pass sediment Automation
Toro Negro 1	Active	8.6	Refurbish Powerhouse Mechanical, electrical equipment improvements Penstocks replacement Restore diversions with Tyrolean weirs Automation
Toro Negro 2	Inactive	1.9	Refurbish Powerhouse Mechanical, electrical equipment improvements Penstocks replacement Electrical equipment upgrades Automation
Garzas 1	Active	7.2	Mechanical, electrical equipment improvements Penstock replacement Restore diversions with Tyrolean weirs Automation
Garzas 2	Inactive	5.0	Mechanical, electrical equipment improvements Penstock replacement Restore diversions with Tyrolean weirs Automation

FACILITY	STATUS	EXISTING CAPACITY (MW)**	IMPROVEMENT NEEDS
Río Blanco	Inactive*	5.0	Mechanical, electrical equipment improvements Dredging Tyrolean weirs to reduce sediment Replace pipelines between Cuboy and Sabana Automation
Dos Bocas	Active	15.0	Mechanical, electrical equipment improvements Restore small diversions Automation
Caonillas 1	Inactive	20.0	Mechanical, electrical equipment improvements Restore small diversions Automation
Caonillas 2	Inactive	4.0	New unit, mechanical, electrical equipment Restore small diversions Turbine restoration or replacement Automation Tunnel cleaning and restoration

***Facility has not been in operation since May 2011 as a result of penstock integrity concerns.**
**** The facilities that are currently inactive are presented as operational with estimated or historical capacity.**

4.1 CAONILLAS/DOS BOCAS

The Dos Bocas-Caonillas Hydroelectric System includes three plant developments; Caonillas 2, Caonillas 1, and Dos Bocas. These are all part of a cascading system of lakes, rivers, and tunnels. Caonillas 2 receives its flow from three diversion structures by a tunnel and penstock. Flow from Caonillas 2 is discharged into the Jordan diversion, which may then be conveyed through a tunnel to the Caonillas reservoir upstream of Caonillas 1.

4.1.1 Dos Bocas

4.1.1.1 Output and Cost to Operate Existing Facilities

The Dos Bocas system has a potential capacity to generate 18 MW at 2.3 kilovolts (kV); however it is limited to 15 MW due to water availability.

The Dos Bocas hydroelectric facility was constructed in 1942 and consists of a three-unit powerhouse with an original rated capacity of 18.6 MW, but currently, the facility is rated at 15MW. The total annual electricity produced over the 30-year study period is about 24,000 MWh. The average existing cost of operating this facility is about $887,400 annually.

4.1.1.2 Physical Condition of Existing Facilities

The Dos Bocas facility consists of three Francis-type turbines. The Dos Bocas reservoir is filled with sediments drawn into the turbines, causing operational problems. In addition, Unit 2 has experienced a decrease in efficiency, which could be a consequence of premature wear due to sediment passing through the turbine. This situation should be addressed along with several mechanical, electrical, instrumentation, control, and communications improvements to improve the facility's reliability.

4.1.2 Caonillas 1

4.1.2.1 Output and Cost to Operate Existing Facilities

Table 4-7, Caonillas 1 - Summary of Average Existing Costs, shows the average cost over the 30-year study period before implementing any improvements.

The Caonillas 1 dam and powerhouse were built in 1948. The powerhouse contains two vertical Francis turbines coupled with generators to produce 10 MW each. Even though there is no production, there is a cost incurred to maintain the facility. The average annual cost to maintain the facility before the improvement implementation is about $293,000. The average existing cost represents an estimation of the cost of operations and maintenance related to each facility.

4.1.2.2 Physical Condition of Existing Facilities

Caonillas 1 requires several mechanical equipment rehabilitation and improvements, some due to the damage suffered during Hurricane Maria. The tunnel from the Jordan diversion to Lago Caonillas is 50% filled with sediment, limiting the flow of water and energy production potential of the facility. The facility's generator step-up transformers are operating beyond their design life.

4.1.3 Caonillas 2

4.1.3.1 Output and Cost to Operate Existing Facilities

Table 4-8, Caonillas 2 - Summary of Average Existing Cost, shows the average cost over the 30-year study period before any improvement is implemented.

The Caonillas 2 facility contains a Francis turbine with a 3.6 MW capacity. The plant has been out of service since 1998 due to Hurricane George. Therefore, there is no current electric power production. Even though the facility is not in service, there is a cost incurred to maintain the facility. The average annual cost to maintain the facility before the improvement implementation is about $13,400. The average existing cost represents an estimation of operations and maintenance related to each facility.

Additional generation can be achieved by the automation of the Dos Bocas-Caonillas system. Additionally, the reestablishment of water flow through Caonillas 2 will create direct Hydroelectric power generation benefits for Caonillas 1.

4.1.3.2 Physical Condition of Existing Facilities

The Caonillas 2 powerhouse has been out of service since 1998 due to hurricane George. The facility has been exposed to flooding, and most of the electrical generation and mechanical equipment needs to be replaced.

4.2 TORO NEGRO

The Toro Negro Hydroelectric System includes two powerhouses (Toro Negro 1 and 2), two major reservoirs (El Guineo and Matrullas), twelve diversion structures, a splitter box, and a series of tunnels, penstocks, and canals. Toro Negro 2 receives its flow from El Guineo via a penstock. Flow from Toro Negro 2 and the diversion structures is combined in a common splitter box before being conveyed through a tunnel crossing Puerto Rico's central divide and then discharging through a canal to the Aceitunas forebay, which then routes the flow to Toro Negro 1.

4.2.1 Toro Negro 1

4.2.1.1 Output and Cost to Operate Existing Facilities

The Toro Negro 1 facility contains four Pelton-type turbines with a total plant capacity of 8.64 MW. Given the current conditions of the plant and its water sources, the average annual electricity produced is 8,782 MWh. The average annual cost to maintain the facility prior to the implementation of improvements is about $1,043,200. The average existing cost represents an estimation of the cost of operations and maintenance related to each facility, including an allocation of staff shared among the two plants in the system. Additional generation can be achieved via automation of the Toro Negro system and rehabilitating the existing diversion dams.

4.2.1.2 Physical Condition of Existing Facilities

The powerhouse, constructed in 1929, contains three 1.44 MW Pelton turbines (Unit 1-1, 1-2, 1-3) and one 4.48 MW Pelton type turbine (Unit 1-4), which was added later in 1937. The powerhouse appeared to be in good operating condition and require some minor maintenance works. The penstocks need to be replaced along with some mechanical and electrical equipment that is operating beyond its useful life.

4.2.2 Toro Negro 2

4.2.2.1 Output and Cost to Operate Existing Facilities

Table 4-3, Toro Negro 2 - Summary of Average Annual Costs, shows the average cost over the 30-year study period before implementing any improvement.

The Toro Negro 2 facility contains one Pelton-type turbine with a 1.92 MW capacity. The historical average annual net generation is 1,910 MWh. However, there is no current electric power production. Even though there is no production, costs are incurred to maintain the facility. The average annual cost to maintain the facility prior to the improvement implementation is about $143,300. The average existing cost represents an estimation of the cost of operations and maintenance related to each facility.

4.2.2.2 Physical Condition of Existing Facilities

The roof of the powerhouse roof needs to be repaired as described in Task 200 of this study. The penstock requires an inspection and replacement of several sections. The electrical equipment at the powerhouse has components that have exceeded its design life; including the oil-filled circuit breaker. Much of the mechanical equipment is near or at the end of its useful life.

4.3 GARZAS

The Garzas Hydroelectric System includes two powerhouses (Garzas 1 and Garzas 2), the Garzas reservoir, and six diversion structures. Garzas 1 receives its flow from the Garzas Reservoir, routed through Garzas 1 to Garzas 2.

4.3.1 Garzas 1

4.3.1.1 Output and Cost to Operate Existing Facilities

The Garzas 1 facility contains two new Pelton-type turbines with a total plant capacity of 7.2 MW. The historical average annual net generation is 7,250 MWh. The average annual electricity produced prior to improvement implementation is 6,777 MWh, and the average existing cost of operating this facility is about $226,665. Additional generation can be achieved by automation of the Garzas system and restoring the small diversions. The average existing cost represents an estimation of the cost of operations and maintenance related to each facility, including an allocation of staff shared among the two plants in the system.

4.3.1.2 Physical Condition of Existing Facilities

Garzas 1 civil structures appear to be in good condition, but the penstock has been in service for over 70 years. In addition, much of the electrical equipment has exceeded its design life.

4.3.2 Garzas 2

4.3.2.1 Output and Cost to Operate Existing Facilities

Table 4-5, Garzas 2 - Summary of Average Annual Costs, shows the average cost and the average annual electricity produced over the 30 year study period before any improvement is implemented.

The Garzas 2 facility contains a double over-hung Pelton-type turbine and a single generator with a 5.04 MW capacity. The facility has been out of service since 2017. Even though there is no production, there is some cost incurred in maintaining the facility. The average annual cost to maintain the facility prior to the improvement implementation is about $104,300. The average existing cost represents an estimation of the cost of operations and maintenance related to each facility.

4.3.2.2 Physical Condition of Existing Facilities

Black & Veatch has identified some improvements that are recommended for this facility. Some of the electrical equipment has exceeded its useful life and remain idle, so the reliability of these electrical equipment are uncertain. The penstock, which has been in service for over 70 years, should be inspected and its replacement considered. The Barreal diversion, due to its inaccessibility, should be replaced with Tyrolean Weir.

4.4 YAUCO

The Yauco Hydroelectric System includes one inactive and one active powerhouses (Yauco 1 and Yauco 2) and five reservoirs (Yahuecas, Guayo, Prieto, Luchetti, and Loco) connected by a series of tunnels. Yauco 1 is a one-unit powerhouse, and Yauco 2 is a vintage two-unit powerhouse, built in 1953.

4.4.1 Yauco 1

4.4.1.1 Output and Cost to Operate Existing Facilities

The Yauco 1 Hydroelectric facility is comprised of a one-unit powerhouse with an original rated capacity of 25 MW. The existing capacity is effectively zero, as the turbine needs major repair or replacement. Even though there is no production, there is a cost incurred to maintain the facility. The average annual cost to maintain the facility prior to the improvement implementation is about $139,900. The average existing cost represents an estimation of the cost of operations and maintenance related to each facility, including an allocation of staff shared among the two plants in the system.

4.4.1.2 Physical Condition of Existing Facilities

The civil facilities at Yauco 1 appear to be in good condition, but two reservoirs need to be dredged and the cooling water intakes cleaned out to return to full capacity. Some of the electrical equipment is beyond its useful life. Several improvements to the mechanical equipment must be completed.

4.4.2 Yauco 2

4.4.2.1 Output and Cost to Operate Existing Facilities

Table 4-12, Yauco 2 - Summary of Average Existing Costs, shows the average cost and over the 30 year study period before any improvement is implemented.

The Yauco 2 hydroelectric facility is comprised of a two-unit powerhouse with an original rated capacity of 9 MW. Yauco 2 is a 1954 vintage powerhouse and appears to be in good condition. The average annual electricity produced prior to improvement implementation is 7,500 MWh, and the average annual cost of operating this facility over the 30-year study period is about $166,600. The average existing cost represents an estimation of the cost of operations and maintenance related to each facility.

4.4.2.2 Condition of Existing Facilities

The civil facilities at Yauco 2 are in serviceable condition; however, the main concern is the accumulation of sediment at the cooling water filter intakes and tunnels. Dredging the Yahuecas and Prieto reservoirs may be part of the solution. Some of the electrical equipment is beyond its useful life.

4.5 RIO BLANCO

The Río Blanco hydroelectric facility is a series of diversion dams, flow conveyance, and the powerhouse. The Cubuy dam diverts water from the Cubuy River into the flow conveyance system. The Sabana dam diverts water from the Sabana River into the flow conveyance system. The Icacos dam creates a small storage reservoir on the Icacos River, and diverts flow into the conveyance system. The Prieto dam diverts water from the Prieto River into the flow conveyance system and the penstock intake.

4.5.1.1 Output and Cost to Operate Existing Facilities

The Río Blanco hydroelectric facility is comprised of a two-unit powerhouse with an original rated capacity of 5 MW. Río Blanco is a 1930 vintage powerhouse and appears to be in good condition. The facility is currently inactive because of concerns with the integrity of the penstock. Even though there is no production, there is a cost incurred to maintain the facility. The average annual cost to maintain the facility prior to the improvement implementation is about $384,600. The average existing cost represents an estimation of the cost of operations and maintenance.

4.5.1.2 Physical Condition of Existing Facilities

The Río Blanco powerhouse has been out of service over the past ten years and appears to be in good condition. Repairs to the flow conveyance system are required, and the turbines appear to be in good condition. Some of the electrical equipment is beyond its useful life, including the oil-filled circuit breakers in the powerhouse.

5 Hydroelectric System Evaluated Improvements

Black & Veatch has evaluated improvement options for each Hydroelectric Facility. These improvements either return the facility to operating conditions or rehabilitate currently operating facilities for improved operations. A description of the potential improvements and the associated benefits or need for the improvements, projected output once fully implemented and in operation, total O&M cost and total capital cost are provided in this section.

5.1 CAONILLAS/DOS BOCAS

5.1.1 Dos Bocas

The Dos Bocas improvements evaluated include repairing or replacing the equipment at this facility and the execution of improvements at the Caonillas 2 plant, upstream from Caonillas 1 and Dos Bocas.

The best opportunity for improving performance at Dos Bocas is to increase storage in the entire Caonillas/Dos Bocas system. Some of the options considered include dredging the reservoir, raising dam levels, diverting water upstream to Lago Caonillas (Caonillas 1 Reservoir), and changing reservoir operations (rule curve 1, rule curve 2).

Other improvements are focused on maintaining the facility in a reliable and safe operating condition. The first component refers to replacing water filters with new duplex strainers or automatic backflushing strainers to maintain cooling water flow and prevent filters from plugging. The second component includes the inspection and repair of Unit 2, and the third component is related to updating governors from mechanical to digital and new operator interface terminals. The station's electrical system is near the end of its design life, and the risk of failure is evident, so there is the need to replace transformers and station service switchgear soon. Also, improvements to communication systems with Caonillas 1 and Caonillas 2 for monitoring and/or automation are recommended. These improvements were grouped into eight scenarios that result in different energy output, O&M costs, and capital investment requirements.

Table 5-1, Summary of Dos Bocas Output, O&M, and Capital Cost, provides the facility's highest potential energy output produced in a given year, the average annual O&M over the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-1 Summary of Dos Bocas Output, O&M, and Capital Cost

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)**	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Refurbished plant	30,700	1,566,900	5,946,000	936.4
2	Refurb with 3.6 MW Caonillas 2	30,000	1,566,900	5,946,000	915.0
3	Refurb with 1 MW Caonillas 2 no bypass	30,650	1,566,900	5,946,000	934.8
4	Refurb with 1 MW Caonillas 2 with bypass	30,650	1,566,900	5,946,000	934.8
5	Refurb with 2 MW Caonillas 2 no bypass	30,500	1,566,900	5,946,000	930.3
6	Refurb with 2 MW Caonillas 2 with bypass	30,500	1,566,900	5,946,000	930.3
7	Refurb with 1 MW Caonillas 2 with bypass with rule curve 1	29,500	1,566,900	5,946,000	899.8
8	Refurb with 1 MW Caonillas 2 with bypass with rule curve 2	29,500	1,566,900	5,946,000	899.8

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.1.2 Caonillas 1

The improvements at Caonillas 1 are focused on repairing and returning the facility to operating condition. The best opportunity for Caonillas 1 is to restore Caonillas 2 diversions and clean out the tunnel from the Jordan Diversion to Lago Caonillas. Equipment damaged by flooding during Hurricane Maria should be replaced. The plant control system must be upgraded to avoid integrating new governors into existing, outdated unit controllers. The communications system with Dos Bocas and Caonillas 2 should be upgraded to ensure reliable monitoring, especially for the small diversions. Other modifications to the drainage system should be completed to avoid future flood damage. These improvements were grouped into six scenarios that result in different outputs, O&M costs, and capital investment requirements.

Table 5-2, Summary of Caonillas 1 Output, O&M, and Capital Cost, provides the facility's highest potential output produced in a given year, the average annual O&M cost over the 30 year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-2 Summary of Caonillas 1 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)**	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Refurbished plant	38,800	1,191,900	2,795,000	1,144.6
2	Refurb with 3.6 MW Caonillas 2	43,700	1,191,900	2,795,000	1,289.2
3	Refurb with 1 MW Caonillas 2 no bypass	50,600	1,191,900	2,795,000	1,492.7
4	Refurb with 1 MW Caonillas 2 with bypass	54,400	1,191,900	2,795,000	1,604.8
5	Refurb with 2 MW Caonillas 2 no bypass	50,300	1,191,900	2,795,000	1,483.9
6	Refurb with 2 MW Caonillas 2 with bypass	54,400	1,191,900	2,795,000	1,604.8
7	Refurb with 1 MW Caonillas 2 with bypass with rule curve 1	53,900	1,191,900	2,795,000	1,590.1
8	Refurb with 1 MW Caonillas 2 with bypass with rule curve 2	54,000	1,191,900	2,795,000	1,593.0

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.1.3 Caonillas 2

The improvements that were evaluated for Caonillas 2 include restoring all small diversions, refurbishing the existing 3.6MW turbine, installing a new 1 MW turbine, installing a new 2MW turbine and, installing a new bypass. These improvements were grouped into six scenarios that result in different energy outputs, O&M costs, and capital investment requirements. Implementing these scenarios will directly affect Caonillas 1 and Dos Bocas, so the improvement associated with these systems are not considered independent.

Table 5-3, Summary of Caonillas 2 Output, O&M, and Capital Costs, provides the facility's highest potential output produced in a given year, the average annual O&M over the 30 year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-3 Summary of Caonillas 2 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)**	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Return to service 3.6 MW	3,000	1,485,700	12,660,000	84.0
2	New 1 MW full auto, no bypass	5,200	1,832,600	36,360,000	140.4
3	New 1 MW full auto, with bypass, sediment passage gates	5,200	2,203,100	20,300,000	145.6
4	New 2 MW full auto, no bypass	5,300	1,906,900	37,150,000	143.1
5	New 2 MW full auto, with bypass, sediment passage gates	5,300	2,350,200	21,870,000	148.4

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.2 TORO NEGRO

5.2.2 Toro Negro 1

Improvements to the civil, electrical, and mechanical elements of the Toro Negro 1 facility were evaluated. The scope of the recommended improvements are segmented into three categories: 1) refurbishing of generators, replacement of seals and gaskets, repair or replacement of transformers and other electrical components, and the repair or replacement of penstocks; 2) rehabilitate diversion structures and conveyance systems; and 3) automation of the plant. The automation scenarios are an effort to modernize the plant to allow remote operation and control for optimized and expanded hours of operation, which include, installation of a monitoring system of reservoir levels, a microprocessor-based protection relay suite, automatic synchronizers, digital governor conversion, static excitation system control system upgrade, remote terminal units, restore communication systems, and update the plant supervisory control and data acquisition (SCADA) system for remote operation and control. For each improvement option, various deficiencies are recommended for correction to ensure proper operation. These improvements were grouped into four scenarios that result in different outputs, O&M cost, and capital investment requirements.

Table 5-4, Summary of Toro Negro 1 Output, O&M, and Capital Costs, provides the facility's highest potential output produced in a given year, the average annual O&M cost over the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-4 Summary of Toro Negro 1 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)**	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Refurbish Powerhouse	17,680	5,203,300	38,863,000	530.4
2	Restored Small Diversions	18,850	5,320,800	40,908,000	537.2
3	Small Diversions with full Auto	26,700	5,433,300	42,133,000	761.0
4	Small Diversions with Tyrolean weirs and full Auto	26,300	5,519,700	43,073,000	749.6
5	Small Diversions with Tyrolean weirs and full Auto rule Curve 1	23,915	5,519,700	43,073,000	681.6
6	Small Diversions with Tyrolean weirs and full Auto rule Curve 2	23,985	5,519,700	43,073,000	683.6

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.2.3 Toro Negro 2

Three improvements were evaluated for Toro Negro 2 facility, including two primary rehabilitation and upgrade efforts: 1) replacement of the existing penstock and replace seals,2) upgrade in communications and automation of the facility, and 3) changing reservoir operations. The penstock replacement will reduce reported leakage and produce a more efficient water flow. The automation scenarios are an effort to modernize the plant and allow remote operation and control to optimize operations which include, installation of a monitoring system of reservoir levels, a microprocessor-based protection relay suite, automatic synchronizers, digital governor conversion, static excitation system control system upgrade, remote terminal units, communication systems, and the implementation of the plant SCADA system for remote operation and control. For each improvement option, various civil deficiencies are recommended for correction to ensure proper operation. Lastly, the electrical engineering deficiencies include replacing the oil-filled breakers with vacuum or SF – 6 breakers, installing a fire barrier and replacing the step-up transformer farther away from the powerhouse. These improvements were grouped into the same two scenarios that result in different outputs, O&M costs and capital investment requirements.

Table 5-5, Summary of Toro Negro 2 Output, O&M, and Capital Costs, provides a summary of the facility's highest potential output produced in a given year, the average annual O&M cost over the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-5 Summary of Toro Negro 2 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)**	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Refurbished plant	1,910	1,560,400	21,827,000	54.4
2	Fully Automated	3,015	1,509,300	22,077,000	85.9
3	Fully Automated rule curve 1	3,300	1,509,300	22,077,000	94.1
4	Fully Automated rule curve 2	3,320	1,509,300	22,077,000	94.6

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.3 GARZAS

5.3.1 Garzas 1

Six improvements were evaluated for the Garzas 1 facility, which includes three primary improvement areas: 1) penstock repair or replacement; 2) rehabilitation of the diversion structures, installation of Tyrolean weirs, and repair of conveyance systems; and 3) restore SCADA system and add automation of the facility to modernize operations. The facility's automation includes installing a monitoring system of reservoir diversion inflows and penstock water flow, installing an automated control system with a graphic display on an operator workstation. These improvements were grouped into five scenarios that result in different energy outputs, O&M cost, and capital investment requirements.

Table 5-6, Summary of Garzas 1 Output, O&M, and Capital Costs, provides the facility’s highest potential output produced in a given year, the average annual O&M cost over the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-6 Summary of Garzas 1 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)**	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Electrical Refurbishment	9,000	2,721,800	24,247,000	256.5
2	Small Diversions	9,300	2,765,900	24,717,000	265.1
3	Tyrolean Weirs on small diversions	9,300	2,798,900	25,067,000	265.1
4	Tyrolean Weirs on small diversions, full Auto	10,580	2,761,600	26,347,000	301.5
5	Tyrolean Weirs on small diversions, full Auto Rule Curve 1	12,500	2,761,600	26,347,000	356.3
6	Tyrolean Weirs on small diversions, full Auto Rule Curve 2	12,500	2,761,600	26,347,000	356.3

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.3.2 Garzas 2

Seven improvements were evaluated at the Garzas 2 facility: 1) the replacement of the penstock; 2) the rehabilitation of the diversion structures and installation of Tyrolean weirs, and 3) the installation of communications and automation to optimize operations. These improvements are needed to optimize the facility's production; they include the replacement of the pipe from Barreal with a larger pipe and the automation of the facility through the addition of a monitoring system for the flow levels; and upgrading the plant SCADA system to allow remote operation and control. These improvements were grouped into four scenarios that result in different outputs, O&M cost, and capital investment requirements.

Table 5-7, Summary of Garzas 2 Output, O&M, and Capital Costs, provides the facility's highest potential output produced in a given year, the average annual O&M over the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-7 Summary of Garzas 2 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)**	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Return to service	6,050	2,561,900	23,996,000	169.4
2	Return Small Diversions to service	6,370	2,566,600	24,046,000	178.4
3	Tyrolean Weirs at Small Diversions	6,370	2,594,800	24,346,000	178.4
4	Tyrolean Weirs on small diversions, full Auto	8,070	2,521,800	25,246,000	226.0
5	Tyrolean Weirs on small diversions, full Auto, increase Barreal Pipe	8,290	2,691,000	27,046,000	232.1
6	Tyrolean Weirs on small diversions, full Auto Rule Curve 1	8,800	2,521,800	25,246,000	246.4
7	Tyrolean Weirs on small diversions, full Auto Rule Curve 2	8,860	2,521,800	25,246,000	248.1

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.4 YAUCO

5.4.1 Yauco 1

Three improvements were evaluated at the Yauco 1 facility, which includes: 1) dredging of Yahuecas and other reservoirs; and 2) restoring communications system and upgrade SCADA system to improve remote operation and automation of the facility. The optimization includes mechanical reliability improvements such as repairing and improving the cooling water system, clean out intakes and tunnels, and a new sump pump system, to name a few. Electrical reliability improvements include automation of the needle operation, overhauling the generator, repairing deteriorated components and auxiliaries, rehabilitating the exciter and commutator, adding vibration monitoring instrumentation to the turbine and generator, and modifications to provide safe physical clearances for a bus between the GSU and roof-located switchyard. The option of dredging the Yahuecas and Prieto reservoirs to invert the elevation of the tunnels includes the optimization mentioned above. The dredging is critical because a significant amount of flow is available at the Yahuecas and Prieto reservoirs, increasing flows at Yauco 1. These improvements were grouped into two scenarios that result in different outputs, O&M costs and capital investment requirements.

Table 5-8, Summary of Yauco 1 Output, O&M, and Capital Costs, provides the facility's highest potential output produced in a given year, the average annual O&M cost of the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-8 Summary of Yauco 1 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)*	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Refurbished	33,000	1,605,600	36,600,000	891.0
2	Dredging	55,300	1,526,800	36,600,000	1,493.1
3	Dredging and modify Yahuecas and Prieto to pass sediment (full Auto)	55,300	2,080,400	17,500,000	1,548.4
4	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 1	53,300	2,080,400	17,500,000	1,492.4
5	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 2	54,000	2,080,400	17,500,000	1,512.0

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.4.2 Yauco 2

Three improvements were evaluated at Yauco 2: 1) reliability improvements, and 2) the dredging of the Yahuecas and other reservoirs, and 3) adding automation and updating remote operation capabilities to the facility. The reliability improvements include refurbishing the exciters and commutators, overhauling the generators, and replacing the existing relays. The option of dredging the Yahuecas and Prieto reservoirs to invert the elevation of the tunnels includes the optimization mentioned above. The dredging is critical because a significant amount of flow is available at the Yahuecas and Prieto reservoirs, increasing flows at Yauco 2. These improvements were grouped into two scenarios that result in different outputs, O&M cost, and capital investment requirements.

Table 5-9, Summary of Yauco 2 Output, O&M, and Capital Costs, provides the facility's highest potential output produced in a given year, the average annual O&M of the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-9 Summary of Yauco 2 Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)*	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Refurbished	20,300	665,500	2,700,000	598.9
2	Dredging	27,300	744,400	2,700,000	805.4
3	Dredging and modify Yahuecas and Prieto to pass sediment (full Auto)	27,300	789,100	3,176,000	805.4
4	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 1	19,600	789,100	3,176,000	578.2
5	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 2	22,400	789,100	3,176,000	660.8

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

5.5 RIO BLANCO

5.5.1 Rio Blanco

Currently, Rio Blanco is not operational due to penstock stability issues. Three improvements were evaluated at Rio Blanco and included a combination of the following: 1) penstock replacement; 2) pipe repair and restoration of diversions; 3) equipment updates; and add automation to allow 24-hour operations. The replacement of the existing penstock would increase the net head conditions of the turbine equipment. There are several damaged sections of the conveyance system, which require replacement. Turbine improvement projects include adding an admission vent to the housing and a new digital governor system. These improvements were grouped into four scenarios that result in different outputs, O&M costs and capital investment requirements.

Table 5-10, Summary of Rio Blanco Output, O&M, and Capital Costs, provides the facility’s highest potential output produced in a given year, the average annual O&M cost of the 30-year study period, and the total capital cost incurred over the study period for each proposed improvement.

Table 5-10 Summary of Rio Blanco Output, O&M, and Capital Costs

LINE	IMPROVEMENT:	ANNUAL OUTPUT (MWH)*	ANNUAL O&M ($)*	TOTAL CAPITAL COST ($)***	30-YEAR OUTPUT (GWH)****
1	Existing	5,620	1,597,800	700,000	163.0
2	Restore all diversions (FEMA Grant so zero cost to PREPA)	6,680	1,326,700	700,000	193.7
3	All Diversions, Full Auto	28,890	1,373,700	1,200,000	837.8
4	Tyrolean weirs all diversions, full Auto	28,890	1,408,500	1,570,000	837.8

*Output presented is the highest potential output produced in a given year
** The average O&M of the 30-year study period
*** The total capital cost incurred over the study period of 30 years
**** Total sum of annual ouputs over the 30-year study period

6 Economic Feasibility Analysis

The Economic Feasibility Analysis performed considers the historical operating and financial performance of the Hydroelectric Facilities. Black & Veatch utilized the historical financial information to understand the current cost to operate the Hydroelectric Facilities and incorporated the cost implications and adjustments to implement specific hydroelectric facility improvements. A 30-year cash flow analysis was developed to explicitly demonstrate each hydroelectric facility's cost responsibility before and after implementing specific improvements.

Upon completing the cash flow analysis, an evaluation criteria was utilized to evaluate and rank the economic feasibility of the improvements analyzed. Provide below is a list of evaluation criteria utilized:

1. **Net Present Value (NPV)**: Assess the current value of the forecasted stream(s) of the Hydroelectric Facilities' cash flow.
2. **Annual Unit Cost of Energy**: Denotes the relationship between total annual hydroelectric facility cost and energy output by dividing the total annual cost by the annual output.
3. **Cumulative Cash Flow**: The cumulative total of the annual operating surplus generated by the Hydroelectric Facilities.
4. **Adjusted Payback Period**: A calculation that demonstrates the number of years it takes to recover the initial investment based on the average annual discounted cash flow generated by the improvement.
5. **Levelized Unit Cost of Energy**: Denotes the relationship between the operating surplus and energy output's discounted value to present value. The relationship is determined by dividing the current value of the annual operating surplus by the current energy output value over the forecast period.
6. **Capacity Factor:** The capacity factor provides a ratio between actual electric output and the total potential electric output for a particular Hydroelectric Facility.

Black & Veatch utilized the NPV as the preferred method for evaluating the proposed improvements. Annual cash flows are discounted at a selected discount rate (Black & Veatch has utilized 6.15 percent to reflect PREPA's approximate cost of debt) to determine the value of the future cash flows over the 30-year forecast period. While other evaluation criteria such as adjusted payback, cumulative cash flow, and others are utilized with NPV to provide a perspective on the economic feasibility of a specific project, NPV is utilized as the basis to rank the proposed improvements.

The following section will provide a summary of the general assumptions utilized to perform the analysis defined herein.

6.1 ASSUMPTIONS

In conducting our analyses and in forming an opinion related to the economic feasibility of the proposed hydroelectric facility improvements, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodology utilized by Black & Veatch in performing the analyses follows generally accepted practices for such projections. Such assumptions and methodologies are summarized in this report and are believed to be appropriate for the purpose for which they are used. While Black & Veatch believes that the assumptions are reasonable and the projection methodology valid, actual results may differ materially from those projected, as influenced by the conditions, events, and circumstances that actually occur.

Provided below is a summary of general and hydroelectric facility-specific assumptions.

6.1.1 General Assumptions

- Forecast Period – 30 years (FY 2021 – FY 2050)
- Annual Hydroelectric System Generation Growth – 0%
- General Inflation – 2%
- Renewal and Replacement Rate – 1.33%
- FY 2021 Unit Revenue of Electricity Produced (unit rate, $/MWh) – $226.11
- FY 2021 Cost of PREPA's Aggregate Generation (All Resources) (unit rate, $/MWh) – $181.27
- FY 2021 Current Cost of Hydroelectric Generation (unit rate, $/MWh) – $67.26
- Net Present Value (NPV) Discount Rate – 6.15%
- Financing Assumptions:
  - Interest on long-term debt – 6.15%
  - Term on long-term debt – 30 years
  - Capital for improvements funded by debt – 100%
- Facility Operator
  - Number of Operators depending on each facility and level of automation (see Table 6-1)
  - Hourly Cost Rate - $50.00
- Roaming Facility Operator (Ranger)
  - One Ranger assigned to each of the five hydroelectric systems
  - Hourly Cost Rate - $30.00
- Security Guards
  - One guard assigned at each facility (10), eight hrs./day, 260 workdays per year
  - Hourly Cost Rate - $25
- Maintenance Crew
  - One crew will be assigned to roam among the facilities or each of the five hydroelectric systems
  - Crew size will depend on the complexity of each operation (see Table 6-1)
  - Hourly Cost Crew - $30

6.1.2 Facility Specific Assumptions

Table 6-1 provides specific hydroelectric facility-related human resources impact assumptions associated with implementing certain hydroelectric facility improvements. The improvements analyzed include specific automation (AUTO) and non-automation (NON-AUTO) requirements, one of which is the addition of facility operators. An additional roaming Operator or "Ranger" is also assigned to each system. Some of the smaller facilities may operate without an assigned onsite operator and will be operated remotely with the assistance of a roaming operator.

A Maintenance Crew will be assigned to serve each of the five systems. Some staff will be allocated to each plant to estimate the cost and complexity of maintaining each plant. Table 6-1 outlines the number of incremental facility operators and staff needed to support the implementation of improvements at each facility.

Table 6-1 Hydroelectric Facilities Improvement Human Resources Impact Assumptions

LINE	FACILITY	INSTALL YEAR*	ASSIGNED FULL-TIME FACILITY OPERATORS	ADDITIONAL FACILITY OPERATOR**		ASSIGNED ROAMING OPERATOR***	MAINT. STAFF****
				AUTO	NON-AUTO		
1	Toro Negro 1	2022	2	-1	0	1	4
2	Toro Negro 2	2022	0	0	0	0	1
3	Garzas 1	2022	1	-1	0	1	2
4	Garzas 2	2022	0	0	1	0	1
5	Caonillas 1	2022	0	0	0	0	2
6	Caonillas 2	2022	0	0	1	0	1
7	Dos Bocas	2022	6	-3	0	1	3
8	Rio Blanco	2022	0	0	1	1	2
9	Yauco 1	2022	0	1	1	0	1
10	Yauco 2	2022	1	0	0	1	2

*Denote the improvement's initial date of implementation
**Denotes the hydroelectric facility operator addition based on an automated or non-automated improvement option.
*** Denotes the number of roaming operators assigned to each system, based at the larger facility in the system.
**** Denotes the mandatory maintenance staff addition that coincides with the group of facility improvements developed.

6.1.3 Facility Production Assumptions

The ability of each hydroelectric facility to maximize its energy production capability is primarily based on the nature of the improvement that is implemented and the associated asset maintenance schedule. As such, Black & Veatch has prepared an energy output ramp-up schedule that considers the existing construction and maintenance schedules associated with implementing the proposed improvements and maintaining the Hydroelectric Facilities over the forecast period.

Table 6-2, Hydroelectric Facilities' Improvement Energy Output Assumptions, outlines the forecasted proportion of energy output to be realized on an annual basis per facility over the forecast period. The annual production rates are applied to the total annual energy output capability developed per facility improvement to calculate the annual energy output. In addition, the annual production rate is implemented in the same order presented in Table 6-2 regardless of the implementation year. The schedule outlined in Table 6-2 is based on Year 1 of implementation through Year 30. For space considerations, the table has omitted years in which all the facilities are expected to be at 100% production capacity.

Table 6-2 Hydroelectric Facilities' Improvement Energy Output Assumptions

	YEAR OF INSTALLATION														
FACILITY	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Toro Negro 1	50%	100%	100%	100%	50%	100%	100%	100%	100%	50%	100%	100%	100%	100%	100%
Toro Negro 2	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%
Garzas 1	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%	100%	100%	100%	100%
Garzas 2	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Caonillas 1	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Caonillas 2	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Dos Bocsa	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Rio Blanco	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Yauco 1	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Yauco 2	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

	YEAR OF INSTALLATION														
FACILITY	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
Toro Negro 1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Toro Negro 2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Garzas 1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Garzas 2	100%	100%	100%	100%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Caonillas 1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Caonillas 2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Dos Bocsa	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Rio Blanco	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Yauco 1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Yauco 2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

6.1.4 Facility Capital Spending Plan Assumptions

The maner in which improvements are scheduled and implemented are typically based on some key variables, such as engineering, design, construction, and labor availability, to name a few. The combination of these variables has been considered by Black & Veatch as the proposed Hydroelectric facility improvement is implemented over the forecast period.

Table 6-3, Hydroelectric Facilities' Improvement Capital Spending Assumptions, outlines the anticipated capital spending schedule associated with the Hydroelectric Facilities. The schedule outlined in Table 6-3 is based on a Year 1 implementation, regardless of the year implemented over the forecast period, through Year 30.

Table 6-3 Hydroelectric Facilities' Improvement Capital Spending Assumptions

	YEAR OF INSTALLATION														
FACILITY	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Toro Negro 1	15%	0%	0%	0%	39%	0%	0%	0%	0%	46%	0%	0%	0%	0%	0%
Toro Negro 2	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	96%
Garzas 1	13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	87%	0%	0%	0%	0%
Garzas 2	9%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Caonillas 1	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Caonillas 2	59%	41%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dos Bocsa	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Rio Blanco	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Yauco 1	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Yauco 2	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	YEAR OF INSTALLATION														
FACILITY	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
Toro Negro 1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	68%	0%	0%	0%	0%
Toro Negro 2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Garzas 1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Garzas 2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Caonillas 1	0%	0%	0%	0%	0%	0%	0%	0%	0%	55%	0%	0%	0%	0%	0%
Caonillas 2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dos Bocsa	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Rio Blanco	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Yauco 1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Yauco 2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Black & Veatch understands that certain Hydroelectric Facilities' improvements are scheduled to be grant-funded. The cost associated with these improvements was not considered part of the evaluation completed herein.

6.2 ECONOMIC FEASIBILITY BY HYDROELECTRIC FACILITY

The economic feasibility analysis by Hydroelectric Facility provides an individual facility's economic feasibility analysis of all the recommended improvements. Upon simulating the cost of implementing each improvement per facility and forecasting the associated energy output, the evaluation criteria are utilized to determine each improvement's economic feasibility. It is important to note that certain Hydroelectric Facilities evaluated in this study are currently inactive. The cost associated with restoring these facilities to the proper working condition has been considered in the evaluation presented herein.

Provided below is an output of the key variables and results of the economic feasibility analysis for each hydroelectric facility's recommended improvements. NPV and adjusted payback period are utilized as the basis to assess each improvement.

6.2.1 Dos Bocas

Dos Bocas is currently an active hydroelectric facility. The improvements completed at this facility will be directly impacted by the improvements made at Caonillas 2. The Caonillas 2 improvements recommended include implementing a bypass and replacing generators for smaller units; that will be more efficient given the existing water flow constraints. Table 6-4 shows specific results of recommended improvements. The NPV of improvements is impacted by the capacity factor improvements provided at Caonillas 2. The improvements to this facility produced an NPV of $95.3 million over the 30 year forecast period. The capital-related cost is about $5.95 million, and the adjusted payback period is about 1.3 years.

Table 6-4 Dos Bocas Economic Feasibility Analysis Results

LINE	DOS BOCAS IMPROVEMENT	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Refurbished plant	95,479,000	1,567,000	1.3	5,946,000	23.4%	15.00
2	Refurb with 3.6 MW Caonillas 2	92,881,000	1,567,000	1.3	5,946,000	22.8%	15.00
3	Refurb with 1 MW Caonillas 2 no bypass	95,293,000	1,567,000	1.3	5,946,000	23.3%	15.00
4	Refurb with 1 MW Caonillas 2 with bypass	95,293,000	1,567,000	1.3	5,946,000	23.3%	15.00
5	Refurb with 2 MW Caonillas 2 no bypass	94,737,000	1,567,000	1.3	5,946,000	23.2%	15.00
6	Refurb with 2 MW Caonillas 2 with bypass	94,737,000	1,567,000	1.3	5,946,000	23.2%	15.00
7	Refurb with 1 MW Caonillas 2 with bypass with rule curve 1	91,025,000	1,567,000	1.3	5,946,000	22.5%	15.00
8	Refurb with 1 MW Caonillas 2 with bypass with rule curve 2	91,025,000	1,567,000	1.3	5,946,000	22.5%	15.00

Figure 6-1 below provides a graphical comparison of the calculated NPV for the Dos Bocas improvements.

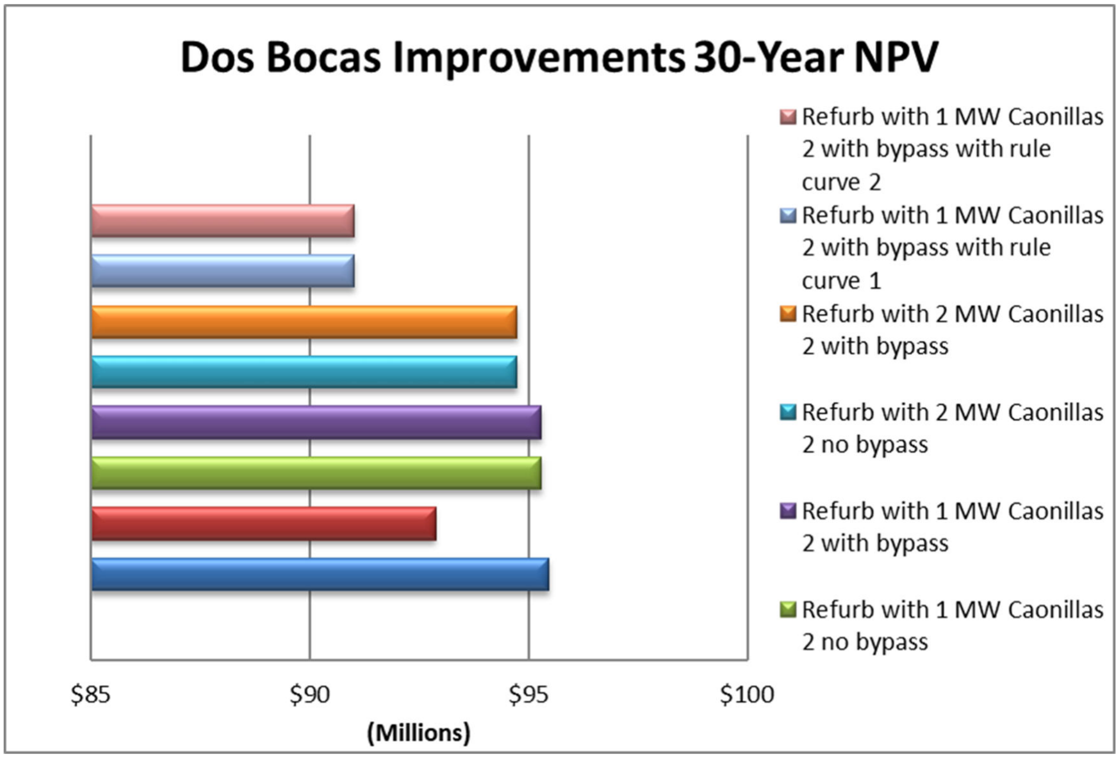


Figure 6-1 Calculated NPV for the Dos Bocas Improvements

6.2.2 Caonillas 1

Caonillas 1 is not an active hydroelectric facility. The recommended improvements at this facility will target the reliability and automation of the facility along with the improvements a Caonillas 2 to provide a more reliable source of water as Caonillas 1 receives a part of its water from Caonillas 2. Line 4 of Table 6-5, provides an improvement that will produce an NPV of about $188.2 million. The capital-related cost is $2.8 million. The adjusted payback period calculated for this improvement is about 0.3 years.

Table 6-5 Caonillas 1 Economic Feasibility Analysis Results

LINE	CAONILLAS 1 IMPROVEMENT	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Refurbished plant	130,297,000	1,192,000	0.4	2,795,000	25.2%	20.0
2	Refurb with 3.6 MW Caonillas 2	148,486,000	1,192,000	0.4	2,795,000	28.3%	20.0
3	Refurb with 1 MW Caonillas 2 no bypass	174,099,000	1,192,000	0.3	2,795,000	32.8%	20.0
4	Refurb with 1 MW Caonillas 2 with bypass	188,204,000	1,192,000	0.3	2,795,000	35.3%	20.0
5	Refurb with 2 MW Caonillas 2 no bypass	172,985,000	1,192,000	0.3	2,795,000	32.6%	20.0
6	Refurb with 2 MW Caonillas 2 with bypass	188,204,000	1,192,000	0.3	2,795,000	35.3%	20.0
7	Refurb with 1 MW Caonillas 2 with bypass with rule curve 1	186,348,000	1,192,000	0.3	2,795,000	35.0%	20.0
8	Refurb with 1 MW Caonillas 2 with bypass with rule curve 2	186,719,000	1,192,000	0.3	2,795,000	35.0%	20.0

Figure 6-2 below provides a graphical comparison of the calculated NPV for the Caonillas 1 improvements.

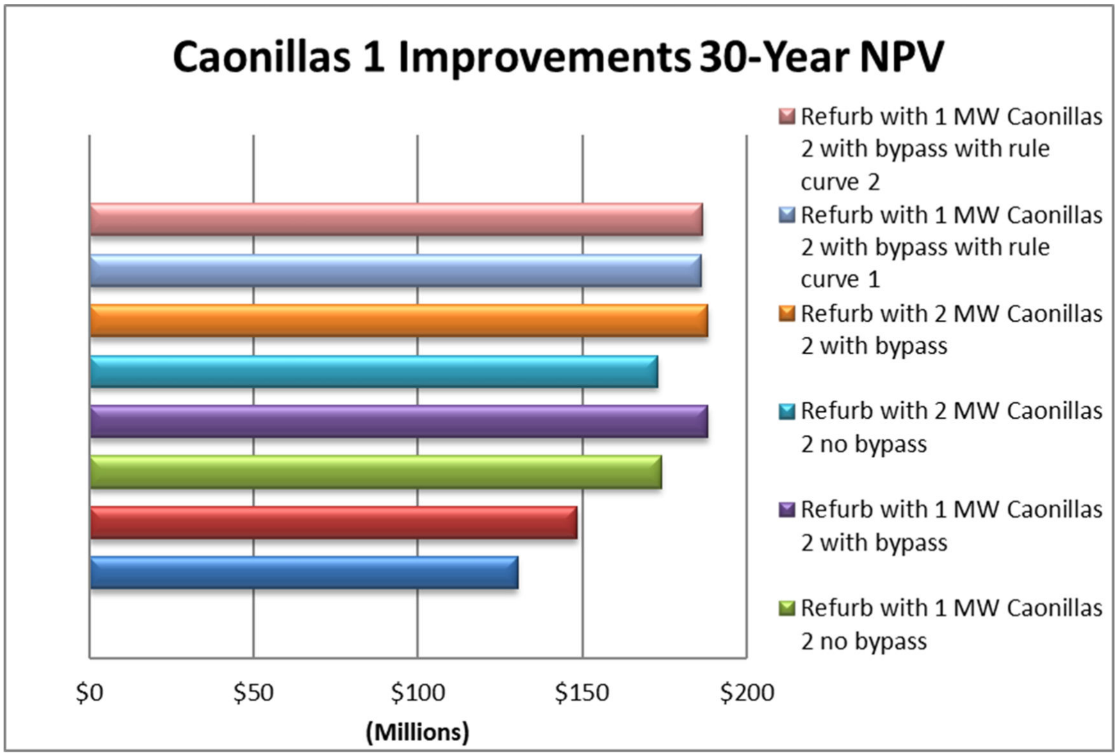


Figure 6-2 Calculated NPV for the Dos Bocas Improvements

6.2.3 Caonillas 2

Caonillas 2 is currently an inactive hydroelectric facility. Several improvements have been recommended to restore the facility to operating condition, and they are related to the rehabilitation or replacement of the existing facility turbine. However, the most important impact of restoring this facility is to provide a reliable additional water source for Caonillas 1 downstream. Line 3 of Table 6-6 provides an improvement that will produce a negative NPV of about ($9.8) million. This improvement produces a negative NPV, but the improvement aligns with the proposed approach to improve water flow at both the Dos Bocas and Caonillas facilities. The capital-related cost to rehabilitate this facility is $20.3 million, and there is no payback period.

Table 6-6 Caonillas 2 Economic Feasibility Analysis Results

LINE	CAONILLAS 2 IMPROVEMENT	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Return to service 3.6 MW	(8,139,000)	1,486,000	NA	12,660,000	34.2%	3.6
2	New 1 MW full auto, no bypass	(7,071,000)	1,833,000	NA	36,360,000	59.4%	1.0
3	New 1 MW full auto, with bypass, sediment passage gates	(9,843,000)	2,203,000	NA	20,300,000	59.4%	1.0
4	New 2 MW full auto, no bypass	(16,667,000)	1,907,000	NA	37,150,000	30.3%	2.0
5	New 2 MW full auto, with bypass, sediment passage gates	(20,288,000)	2,350,000	NA	21,870,000	30.3%	2.0

Figure 6-3 below provides a graphical comparison of the calculated NPV for the Caonillas 2 improvements.

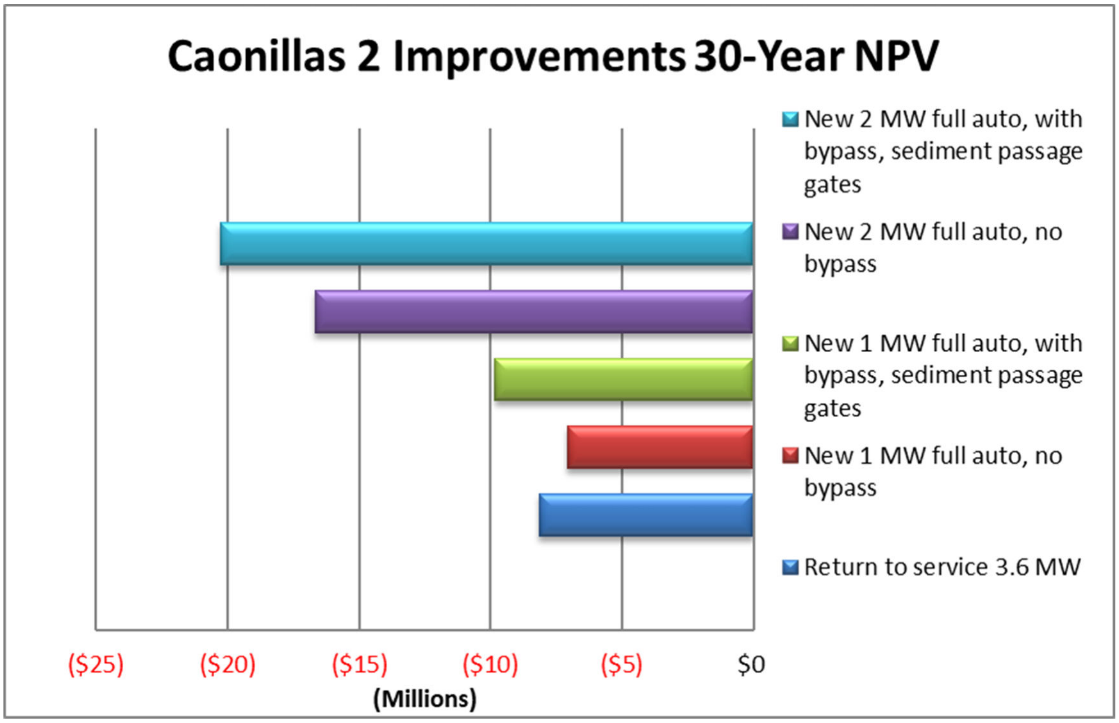


Figure 6-3 Calculated NPV for the Caonillas 2 Improvements

6.2.4 Toro Negro 1

Toro Negro 1 is currently an active hydroelectric facility. Several improvements have been recommended that vary around the rehabilitation or replacement of certain penstock and diversion structures, considering automation in some improvements. While physically in the same region and with some level of interconnection, the independent reservoirs for Toro Negro 1 and Toro Negro 2 allow for different criteria for selecting the best-case scenario for each facility. Line 3 of Table 6-7, Small Diversions with full Automation, provides an improvement that will produce the highest NPV of about ($31.2) million. This improvement produces the highest energy output with a capacity factor of 34.6%. The capital-related cost is $42.1 million. The improvements recommended below assumes the implementation of a new penstock structure. The adjusted payback period for this option is the shortest of all the options at 27 years.

Table 6-7 Toro Negro 1 Economic Feasibility Analysis Results

LINE	TORO NEGRO 1 IMPROVEMENT	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Refurbish Powerhouse	2,378,000	5,203,000	490.3	38,863,000	22.9%	8.6
2	Restored Small Diversions	4,898,000	5,321,000	167.0	40,908,000	24.5%	8.6
3	Small Diversions with full Auto	31,241,000	5,433,000	27.0	42,133,000	34.6%	8.6
4	Small Diversions with Tyrolean weirs and full Auto	28,672,000	5,520,000	30.1	43,073,000	34.1%	8.6
5	Small Diversions with Tyrolean weirs and full Auto rule Curve 1	20,213,000	5,520,000	42.6	43,073,000	31.0%	8.6
6	Small Diversions with Tyrolean weirs and full Auto rule Curve 2	20,461,000	5,520,000	42.1	43,073,000	31.1%	8.6

Figure 6-4 below provides a graphical comparison of the calculated NPV for the Toro Negro 1 improvements.

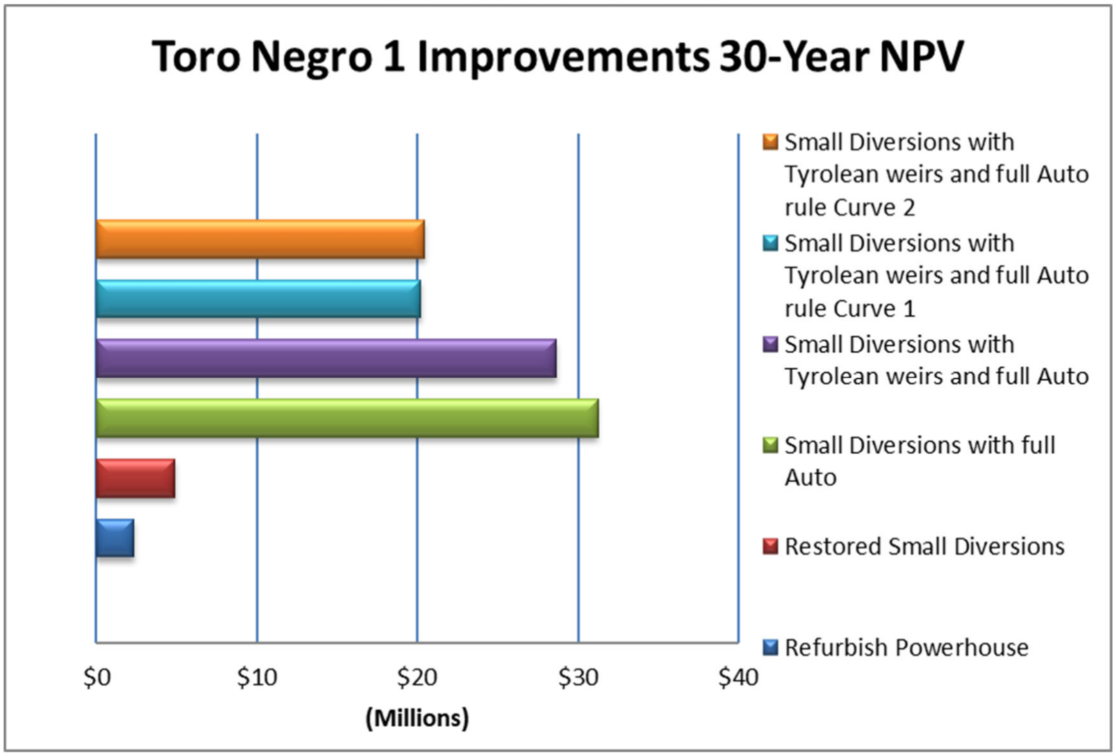


Figure 6-4 Calculated NPV for the Toro Negro 1 Improvements

6.2.5 Toro Negro 2

Toro Negro 2 is currently an inactive hydroelectric facility, however repairs have been made and it is ready for testing on the electrical grid. Several improvements have been recommended to improve the reliability and to maintain the facility properly. These improvements vary around the rehabilitation or replacement of the penstock structure with consideration for automation. While physically in the same region and with some level of interconnection, the independent reservoirs for Toro Negro 1 and Toro Negro 2 allow for different criteria for selecting the best-case scenario for each facility. Line 4 of Table 6-8, Fully Automated rule curve 2, provides an improvement that will produce the least negative NPV of about $(2.5) million. The capital cost is $22.1 million, and there is no payback period associated with this improvement.

Table 6-8 Toro Negro 2 Economic Feasibility Analysis Results

LINE	TORO NEGRO 2 IMPROVEMENT:	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Refurbished plant	(8,212,000)	1,560,000	NA	21,827,000	10.9%	2.0
2	Fully Automated	(3,605,000)	1,509,000	NA	22,077,000	17.2%	2.0
3	Fully Automated rule curve 1	(2,582,000)	1,509,000	NA	22,077,000	18.8%	2.0
4	Fully Automated rule curve 2	(2,510,000)	1,509,000	NA	22,077,000	18.9%	2.0

Figure 6-5 below provides a graphical comparison of the calculated NPV for the Toro Negro 2 improvements.

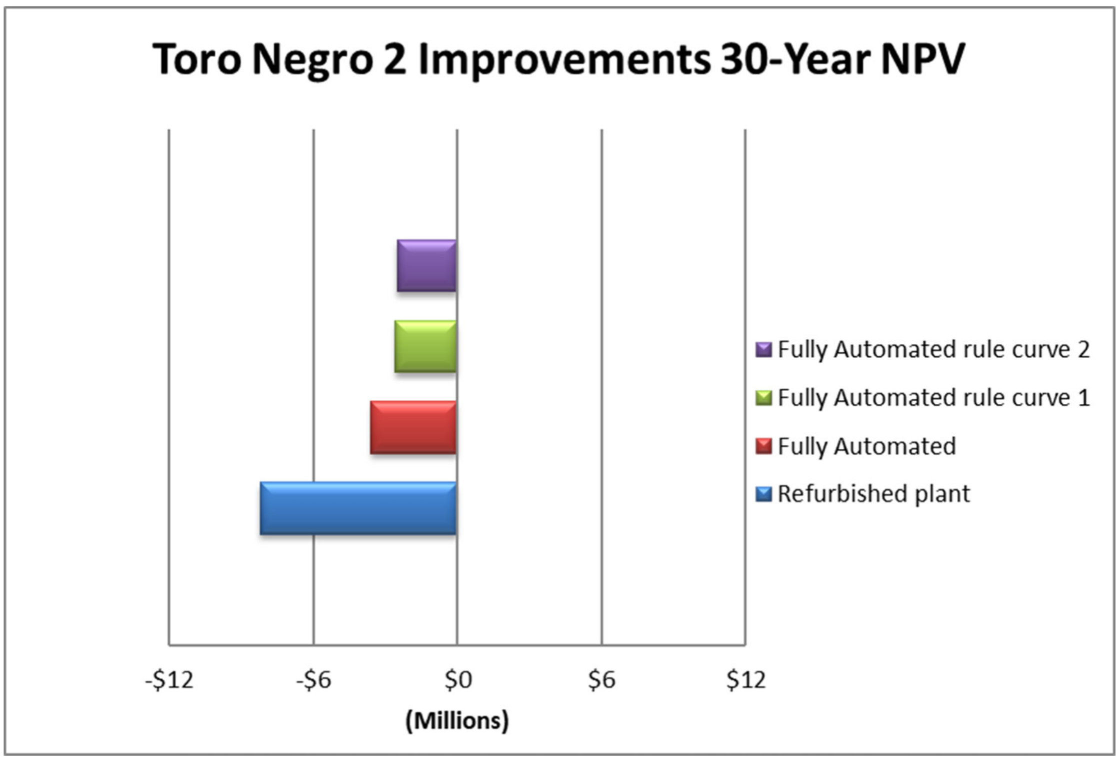


Figure 6-5 Calculated NPV for the Toro Negro 2 Improvements

6.2.6 Garzas 1

Garzas 1 is currently an active hydroelectric facility. Several improvements have been recommended and vary around the rehabilitation or replacement of certain penstock and diversion structures considering automation. Line 5 of Table 6-9, Tyrolean Weirs on small diversions, full Auto Rule Curve 1, provides an improvement that will produce the highest NPV of $23.6 million and an adjusted payback of 22.3 years. This improvement produces the highest energy output with a capacity factor of 19.8% and has the least impact on reservoir levels. The capital-related cost is $26.3 million, which is not the lowest of all improvements. However, the higher Capacity Factor allows the plant to produce significantly more energy and reach a higher NPV.

Table 6-9 Garzas 1 Economic Feasibility Analysis Results

LINE	IMPROVEMENT:	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Electrical Refurbishment	11,969,000	2,722,000	40.5	24,247,000	14.3%	7.2
2	Small Diversions	12,464,000	2,766,000	39.7	24,717,000	14.7%	7.2
3	Tyrolean Weirs on small diversions	12,035,000	2,799,000	41.7	25,067,000	14.7%	7.2
4	Tyrolean Weirs on small diversions, full Auto	16,785,000	2,762,000	31.4	26,347,000	16.8%	7.2
5	Tyrolean Weirs on small diversions, full Auto Rule Curve 1	23,638,000	2,762,000	22.3	26,347,000	19.8%	7.2
6	Tyrolean Weirs on small diversions, full Auto Rule Curve 2	23,638,000	2,762,000	22.3	26,347,000	19.8%	7.2

Figure 6-6 below provides a graphical comparison of the calculated NPV for the Garzas 1 improvements.

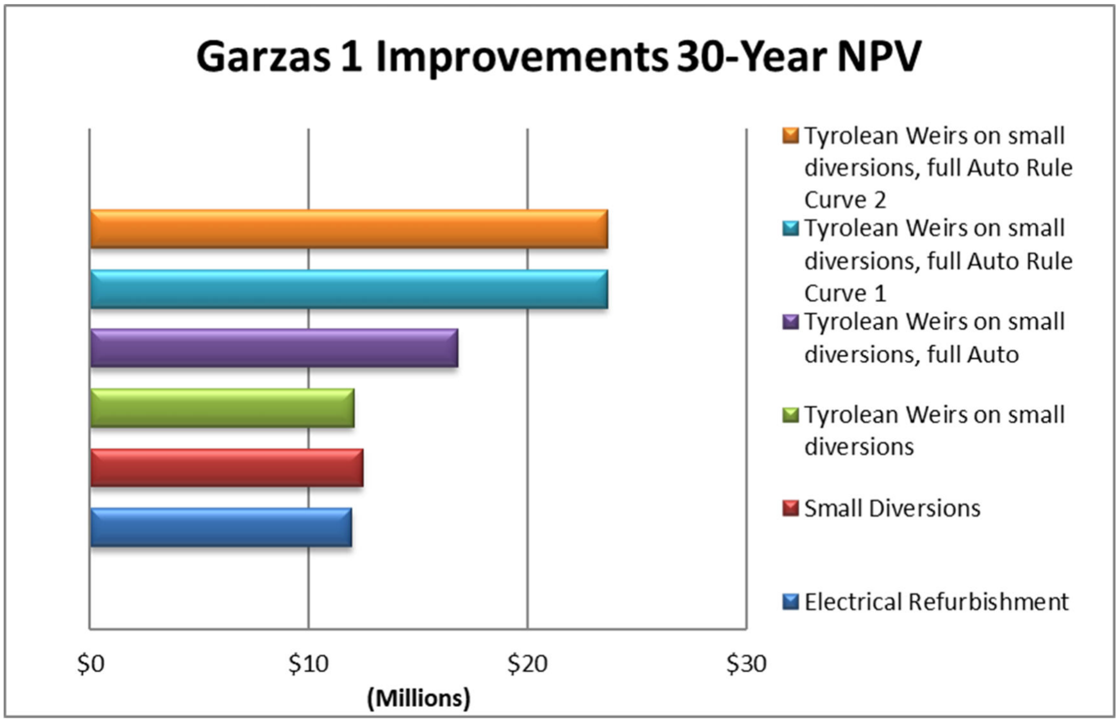


Figure 6-6 Calculated NPV for the Garzas 1 Improvements

6.2.7 Garzas 2

Garzas 2 is currently an inactive hydroelectric facility. Several improvements have been recommended and vary around the rehabilitation or replacement of certain diversion structures to add Tyrolean weirs and reduce the maintenance required. Also, consideration for automation in some improvements will provide the ability to operate remotely. Line 6 of Table 6-10, Tyrolean Weirs on small diversions, full Auto Rule Curve 1, provides an improvement that will produce the 2nd highest NPV of $19.6 million and an adjusted payback period of 25.7 years. This improvement produces the 2nd highest energy output, which maximizes the energy savings potential. The capital-related cost is $25.7 million, which is not the lowest of all improvements but is significantly lower than the improvements that require the implementation of an increased pipe size from the small diversion structure.

Table 6-10 Garzas 2 Economic Feasibility Analysis Results

LINE	GARZAS 2 IMPROVEMENT	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Return to service	9,803,000	2,562,000	49.0	23,996,000	13.8%	5.0
2	Return Small Diversions to service	10,858,000	2,567,000	44.3	24,046,000	14.5%	5.0
3	Tyrolean Weirs at Small Diversions	10,491,000	2,595,000	46.4	24,346,000	14.5%	5.0
4	Tyrolean Weirs on small diversions, full Auto	17,068,000	2,522,000	29.6	25,246,000	18.4%	5.0
5	Tyrolean Weirs on small diversions, full Auto, increase Barreal Pipe	15,632,000	2,691,000	34.6	27,046,000	18.9%	5.0
6	Tyrolean Weirs on small diversions, full Auto Rule Curve 1	19,615,000	2,522,000	25.7	25,246,000	20.1%	5.0
7	Tyrolean Weirs on small diversions, full Auto Rule Curve 2	19,824,000	2,522,000	25.5	25,246,000	20.2%	5.0

Figure 6-7 below provides a graphical comparison of the calculated NPV for the Garzas 2 improvements.

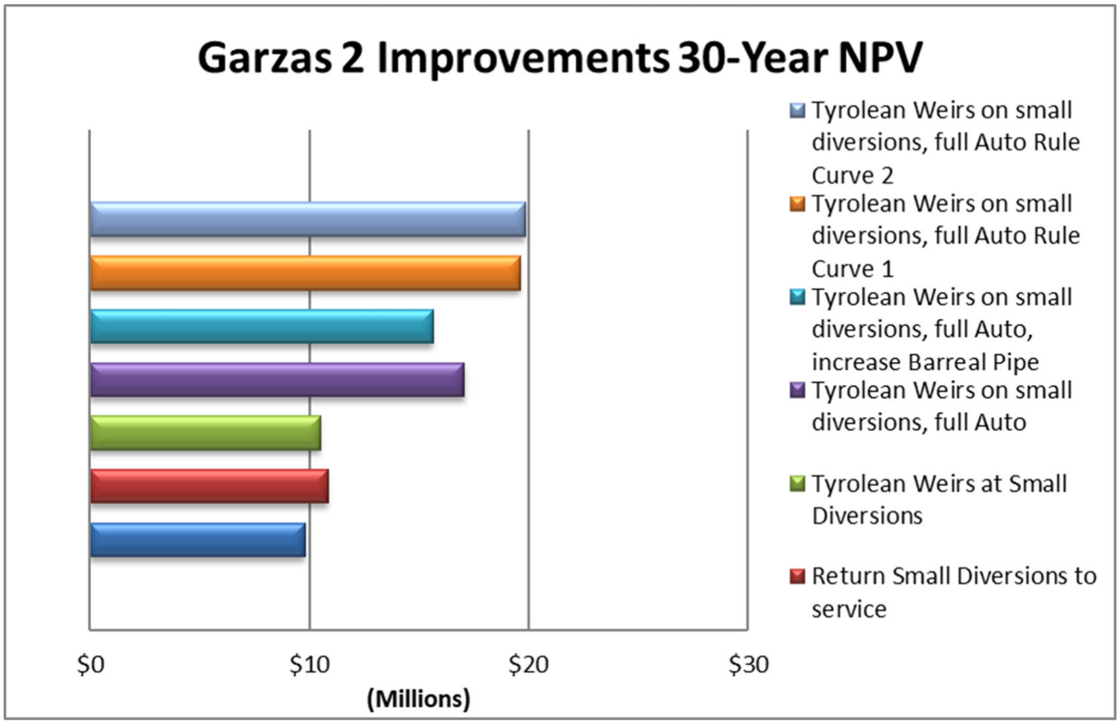


Figure 6-7 Calculated NPV for the Garzas 2 Improvements

6.2.8 Rio Blanco

Rio Blanco is currently an inactive hydroelectric facility. Several improvements have been recommended and vary around rehabilitating or replacing the existing penstock and other piping and turbine repair. Line 4 of Table 6-11, Tyrolean weirs all diversions, full Auto, provides an improvement that has produced an NPV of $87.8 million and an adjusted payback period of only 0.4 years. This improvement is one of the two that produces the highest energy output, and the capital-related cost is $1.6 million.

Table 6-11 Rio Blanco Economic Feasibility Analysis Results

LINE	RIO BLANCO IMPROVEMENT	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Refurbished	2,317,000	1,598,000	6.0	700,000	12.8%	5.0
2	Restore all diversions (FEMA Grant)	9,127,000	1,327,000	1.5	700,000	15.3%	5.0
3	All Diversions, Full Auto	88,214,000	1,374,000	0.3	1,200,000	66.0%	5.0
4	Tyrolean weirs all diversions, full Auto	87,761,000	1,409,000	0.4	1,570,000	66.0%	5.0

Figure 6-8 below provides a graphical comparison of the calculated NPV for the Rio Blanco improvements.

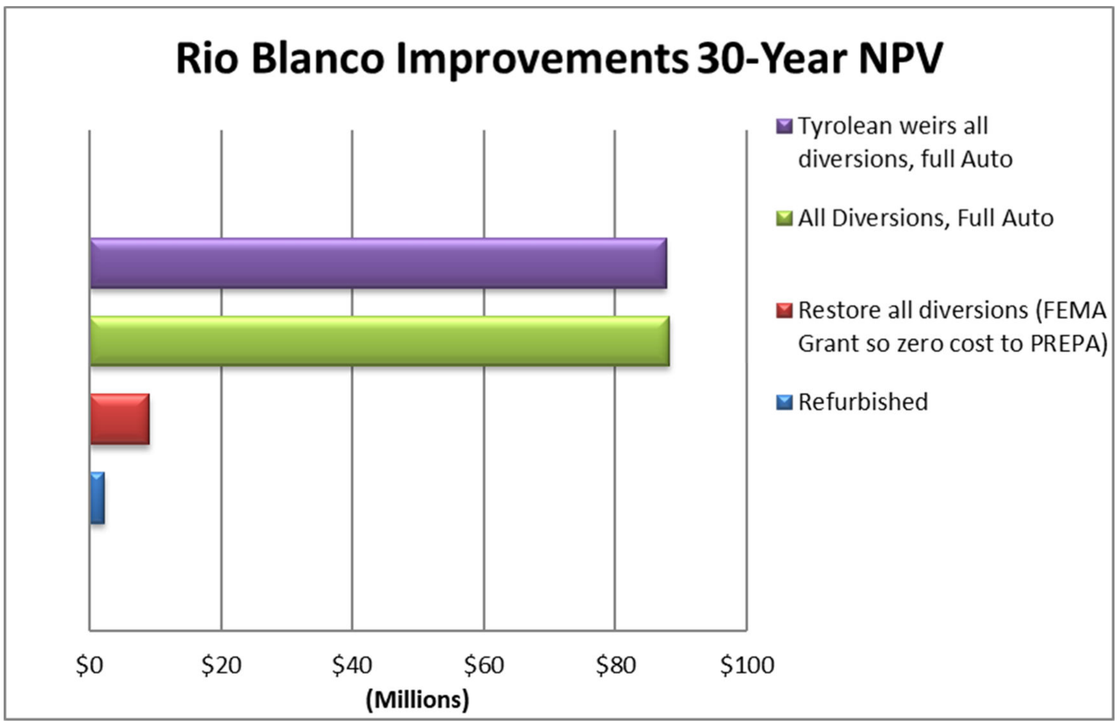


Figure 6-8 Calculated NPV for the Rio Blanco Improvements

6.2.9 Yauco 1

Yauco 1 is currently an inactive hydroelectric facility. Several improvements have been recommended and vary around implementing improvement to the existing Reservoir Operations.

Line 2 of Table 6-12, Dredging, has the highest NPV of $166.5 million for this facility. However, Line 3 of Table 6-12 provides an improvement that will produce the second-highest NPV of about $161.6 million and an adjusted payback period of 2.2 years. It has a much lower investment of $17.5 million. Yauco 1 is the largest hydroelectric facility operated by PREPA at 25.0 MW, and this improvement produces the highest energy output. The capital-related cost of this option, $17.5 million, is the lowest of all the recommended improvements.

Table 6-12 Yauco 1 Economic Feasibility Analysis Results

LINE	YAUCO 1 IMPROVEMENT	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Refurbished	90,159,000	1,606,000	8.1	36,600,000	15.1%	25
2	Dredging	166,491,000	1,527,000	4.4	36,600,000	25.3%	25
3	Dredging and modify Yahuecas and Prieto to pass sediment (full Auto)	161,590,000	2,080,000	2.2	17,500,000	25.3%	25
4	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 1	154,823,000	2,080,000	2.3	17,500,000	24.3%	25
5	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 2	157,192,000	2,080,000	2.2	17,500,000	24.7%	25

Figure 6-9 below provides a graphical comparison of the calculated NPV for the Yauco 1 improvements.

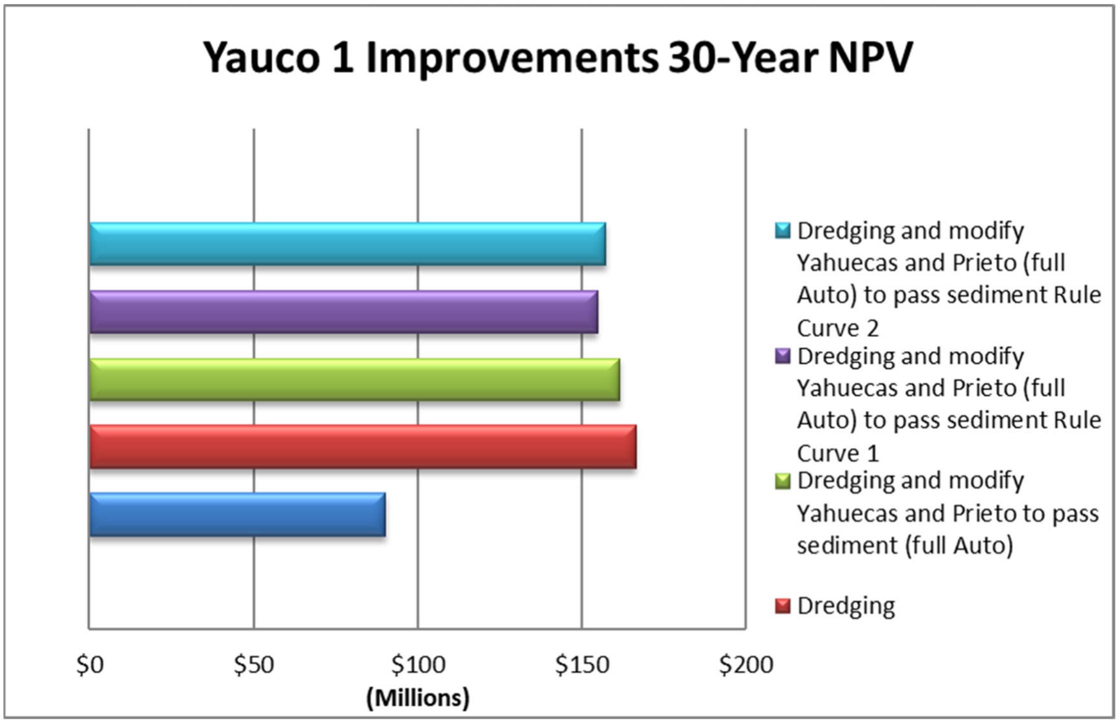


Figure 6-9 Calculated NPV for the Yauco Improvements

6.2.10 Yauco 2

Yauco 2 is currently an active hydroelectric facility. Several improvements have been recommended that vary around implementing improvements to the existing Reservoir Operations. Line 3 of Table 6-20, Dredging and modify Yahuecas and Prieto to pass sediment (full Auto), provides an improvement that will produce the highest NPV of about $92 million and the 2nd lowest adjusted payback period of 0.7 years. The capital-related cost is $3.2 million.

Table 6-13 Yauco 2 Economic Feasibility Analysis Results

LINE	IMPROVEMENT:	NET PRESENT VALUE ($)	ANNUAL AVERAGE COST ($)	ADJUSTED PAYBACK PERIOD (YEARS)	TOTAL CAPITAL COST ($)	CAPACITY FACTOR (%)	FACILITY CAPACITY (MW)
1	Refurbished	67,481,000	666,000	0.8	2,700,000	23.2%	10
2	Dredging	92,591,000	744,000	0.6	2,700,000	31.2%	10
3	Dredging and modify Yahuecas and Prieto to pass sediment (full Auto)	92,008,000	789,000	0.7	3,176,000	31.2%	10
4	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 1	63,426,000	789,000	1.0	3,176,000	22.4%	10
5	Dredging and modify Yahuecas and Prieto (full Auto) to pass sediment Rule Curve 2	73,820,000	789,000	0.9	3,176,000	25.6%	10

Figure 6-10 below provides a graphical comparison of the calculated NPV for the Yauco 2 improvements.

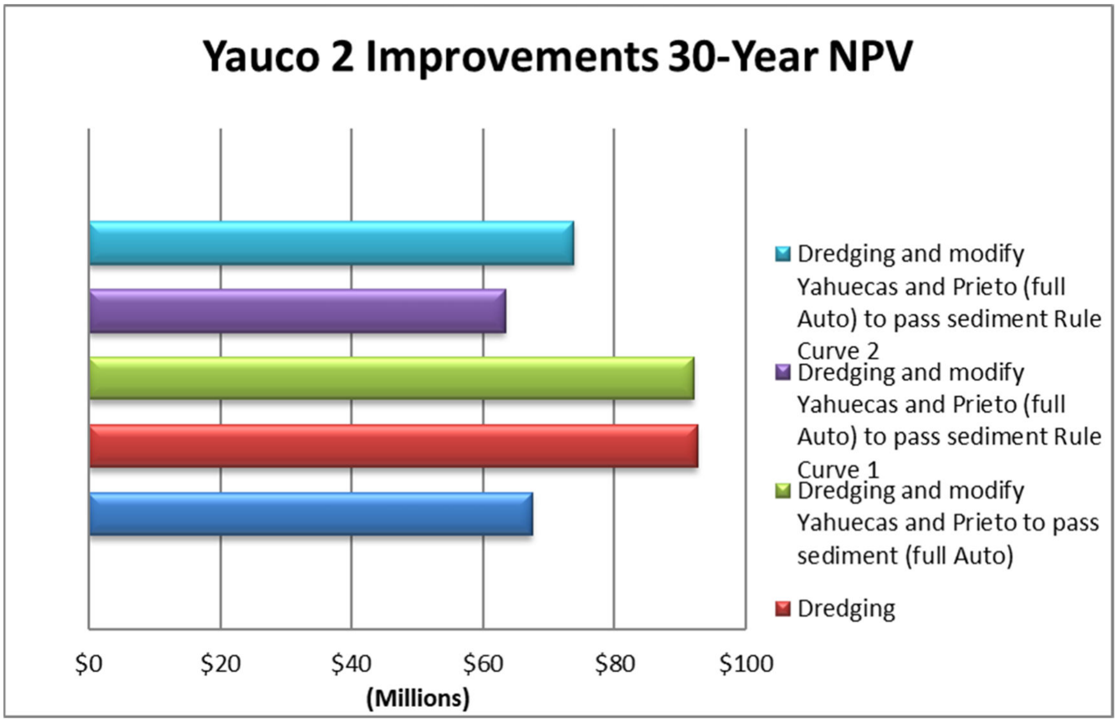


Figure 6-10 Calculated NPV for the Yauco 2 Improvements

6.3 PORTFOLIO ECONOMIC FEASIBILITY BY PORTFOLIO OF HYDROELECTRIC FACILITY AFTER IMPLEMENTATION OF IMPROVEMENTS

The previous section of this Report identified the economic feasibility of each of the potential improvements evaluated for the Hydroelectric Facilities. The Black & Veatch team developed two scenarios or portfolios of improvements for PREPA to consider for implementation. These scenarios include one selected improvement for each facility, as necessary, and portfolio analysis to demonstrate the economic benefit to PREPA to implement the portfolio of improvements. Provide below is a summary of the two scenarios presented herein:

1. Highest NPV Improvement per Hydroelectric System; Portfolio 1
2. Best Implementable per Technical, Geographical and Reasonable Factors; Portfolio 2,

6.3.1 Highest NPV Improvement per Hydroelectric System, Portfolio 1

The portfolio presented herein selects the best performing NPV improvement projects recommended for the respective Hydroelectric Facilities. As such, the portfolio of selected improvements, with a total capital cost of $163.3 million, generates a positive NPV of about $695.8 million over the 30-year study period. The improvement described herein assumes that PREPA moves forward with certain improvements even if the improvement produces a negative NPV given the financial feasibility of the portfolio of improvements.

The following projects listed in Table 6-14 by facility are utilized in this portfolio:

Table 6-14 Portfolio 1 Project Descriptions

LINE	PROJECT NAME	PROJECT DESCRIPTION:	TOTAL CAPITAL COST
1	Dos Bocas	Refurb with 1 MW Caonillas 2 with bypass	$5,946,000
2	Caonillas 1	Refurb with 1 MW Caonillas 2 with bypass	$2,795,000
3	Caonillas 2	New 1 MW full auto, with bypass, sediment passage gates	$20,300,000
4	Toro Negro 1	Small Diversions with full Auto	$42,133,000
5	Toro Negro 2	Existing	$0
6	Garzas 1	Tyrolean Weirs on small diversions, full Auto Rule Curve 2	$26,347,000
7	Garzas 2	Tyrolean Weirs on small diversions, full Auto Rule Curve 2	$25,246,000
8	Yauco 1	Dredging	$36,600,000
9	Yauco 2	Dredging	$2,700,000
10	Rio Blanco	All Diversions, Full Auto	$1,200,000
11	Total		$163,267,000

6.3.1.1 Energy Profile

Figure 6-11, Energy Profile – Highest NPV Improvement per Hydroelectric System, presents a comparison of the energy produced before and after the improvements with total annual energy produced by the facilities. At full implementation, the Hydroelectric Facilities will produce about 250,000 MWh (red-line) of electricity annually, which is more than five times the existing electricity produced of 50,000 MWh (green-line) annually.

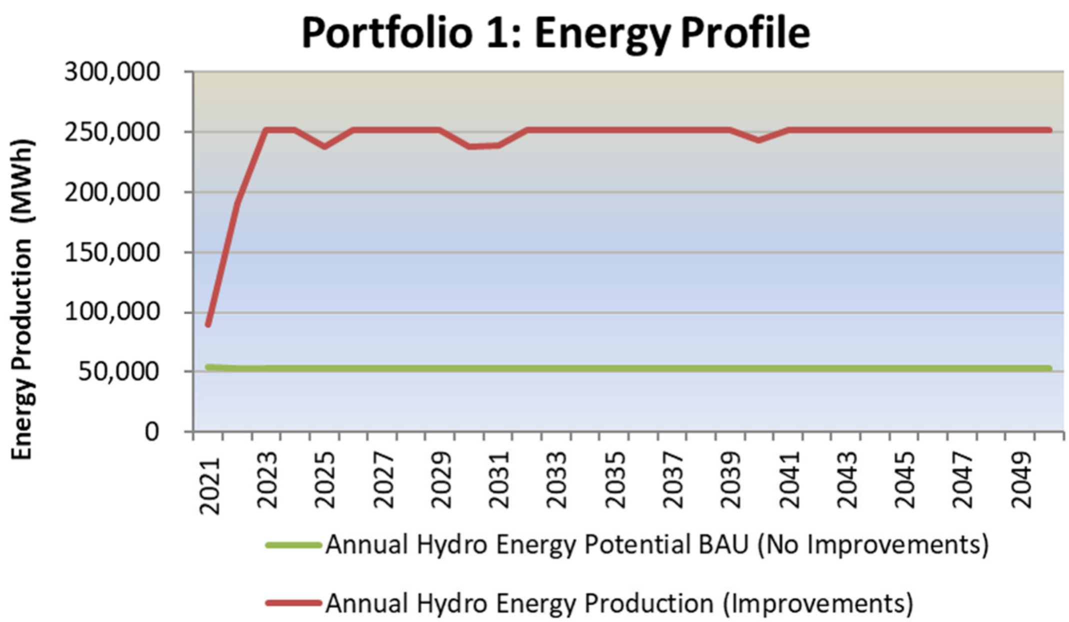


Figure 6-11 Portfolio Energy Profile – Highest NPV Improvement per Hydroelectric Facility

6.3.1.2 Portfolio Capital Costs

Figure 6-12, Capital Spending – Highest NPV Improvement per Hydroelectric System, shows the annual and cumulative capital spending for the 30-year study period. Total capital costs associated with implementing this portfolio of improvements are approximately $163.3 million, as indicated in the figure below. The capital spending associated with this portfolio is initiated in 2021 and completed in 2050, where the cumulative project cost totals $163.3 million.

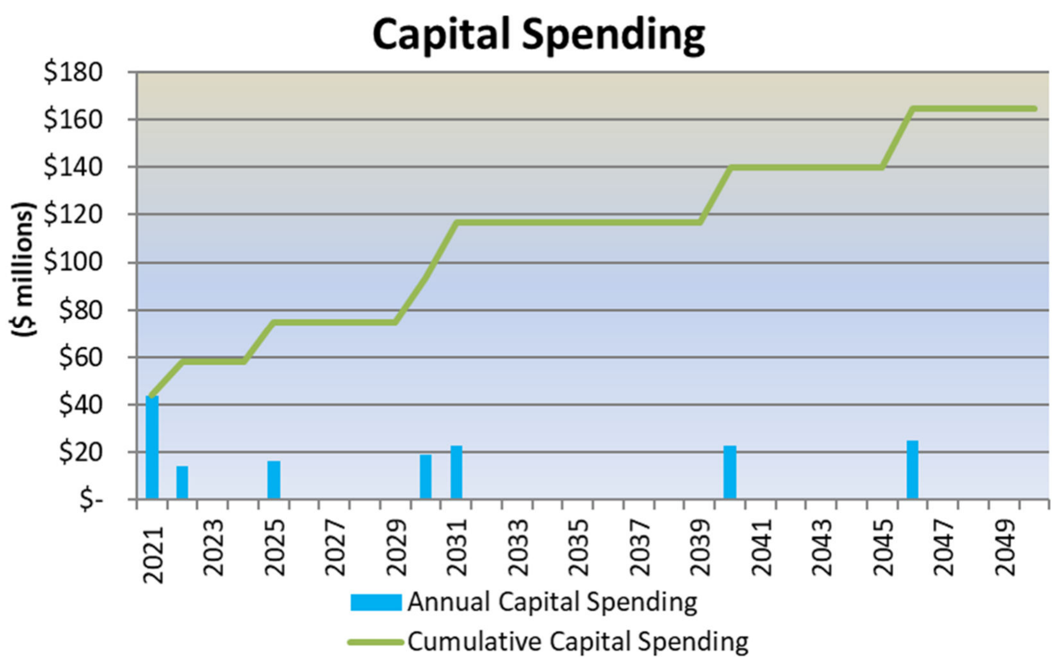


Figure 6-12 Capital Spending – Highest NPV Improvement per Hydroelectric Facility

6.3.1.3 Annual Operating Cash Flow

Figure 6-13, Annual Operating Cash Flow – Highest NPV Improvement per Hydroelectric System, presents a comparison of potential revenues generated from energy produced and the cost associated with implementing the portfolio of improvements. The revenues generated from energy produced represent the potential revenues generated by PREPA due to the incremental increase in energy output. When compared to the cost to operate, existing O&M, incremental O&M, debt service, cash finance capital projects, and renewal and replacement, the revenue potential exceeds the cost to operate, which may provide opportunities for PREPA to achieve cost savings with the implementation of the next increment of Hydroelectric energy.

The annual average operating balance over the 30-year study period is about $34.7 million for the portfolio discussed herein. In 2023, the operating balance realized is estimated to be $57 million, and this total grows to about $76.0 million by 2050. In Figure 6-13, the space below the purple revenue line and above the bar graphs, over the study period, represents PREPA's unit revenue earnings over and above the cost to operate the Hydroelectric Facilities to produce a positive NPV of about $695.8 million.

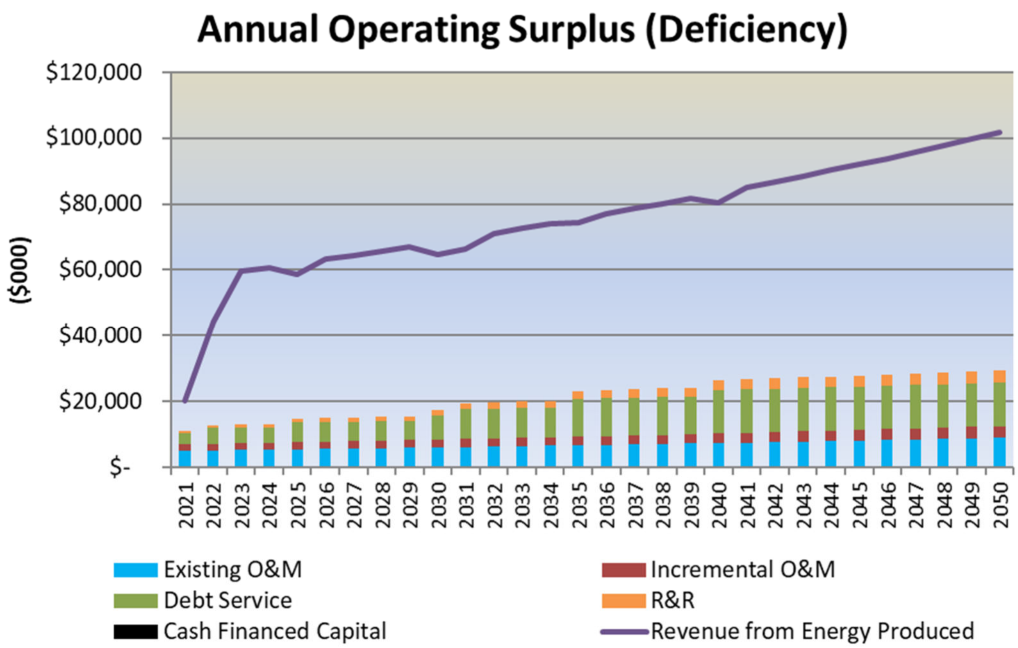


Figure 6-13 Annual Operating Cash Flow – Highest NPV Improvement per Hydroelectric System

6.3.2 Best Implementable per Technical, Geographical and Reasonable Factors; Portfolio 2

Portfolio 2 outlines the improvements that produce the highest portfolio NPV but considers technical, geographic, and reasonable considerations that may result in improved operations and higher reliability of the facilities. Projects that produce a lower or even negative NPV are included in the portfolio because they serve a technical or logistical purpose beyond the NPV of the investment. As such, the portfolio of selected improvements, with a total capital cost of $166.7 million, generates a positive NPV of $687.5 million over the 30-year study period.

The following projects by facility are utilized in this portfolio:

Table 6-15 Portfolio 2 Project Descriptions

LINE	PROJECT NAME	PROJECT DESCRIPTION:	TOTAL CAPITAL COST
1	Dos Bocas	Refurb with 1 MW Caonillas 2 with bypass	$5,946,000
2	Caonillas 1	Refurb with 1 MW Caonillas 2 with bypass	$2,795,000
3	Caonillas 2	New 1 MW full auto, with bypass, sediment passage gates	$20,300,000
4	Toro Negro 1	Small Diversions with full Auto	$42,133,000
5	Toro Negro 2	Fully Automated rule curve 1	$22,077,000
6	Garzas 1	Tyrolean Weirs on small diversions, full Auto Rule Curve 1	$26,347,000
7	Garzas 2	Tyrolean Weirs on small diversions, full Auto Rule Curve 1	$25,246,000
8	Yauco 1	Dredging and modify Yahuecas and Prieto to pass sediment (full Auto)	$17,500,000
9	Yauco 2	Dredging and modify Yahuecas and Prieto to pass sediment (full Auto)	$3,176,000
10	Rio Blanco	All Diversions, Full Auto	$1,200,000
11	Total		$166,720,000

6.3.2.1 Energy Profile

Figure 6-14, Energy Profile – The NPV Portfolio of Improvements, presents a comparison of the energy produced before and after the improvements with total annual hydroelectric energy produced by PREPA. At full implementation, the Hydroelectric Facilities will produce about 250,000 MWh (red-line) of electricity annually, which is five times the existing electricity produced of about 50,000 MWh (green-line). Currently, PREPA produces this energy from all other sources, primarily fossil fuels.

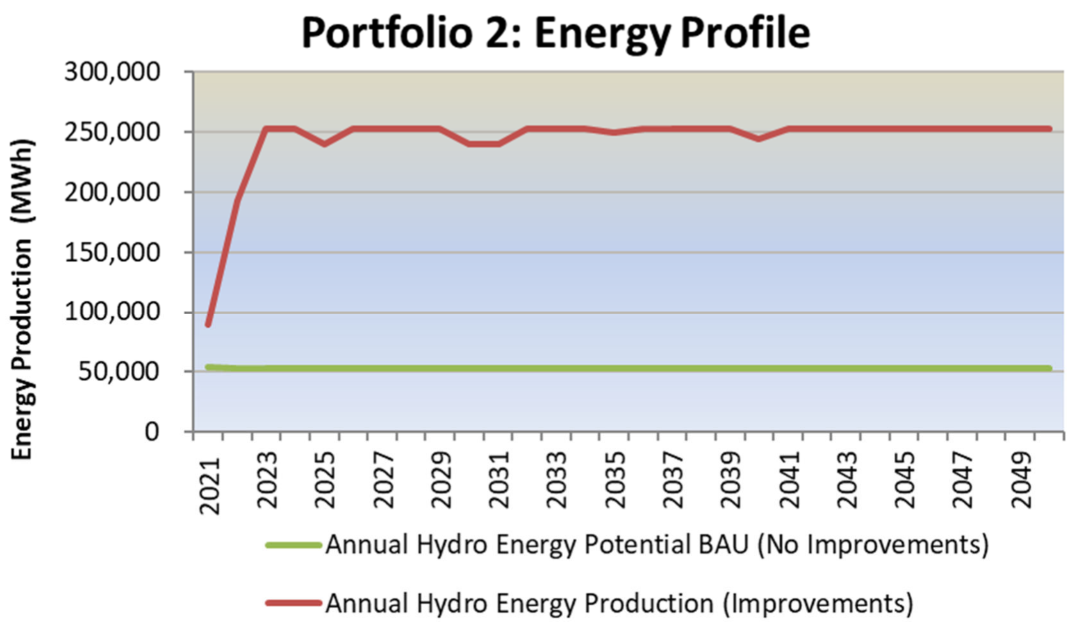


Figure 6-14 Energy Profile – Best Implementable per Technical, Geographical and Reasonable Factors

6.3.2.2 Portfolio Capital Costs

Figure 6-15, Capital Spending – Best Implementable per Technical, Geographical and Reasonable Factors, shows the annual and cumulative capital spending for the 30-year study period. Total capital costs associated with implementing this portfolio of improvements are approximately $166.7 million, as indicated in the figure below. The capital spending associated with this portfolio is initiated in 2021 and completed in 2050, including some replacements that happen in the mid-term of the useful life of the equipment.

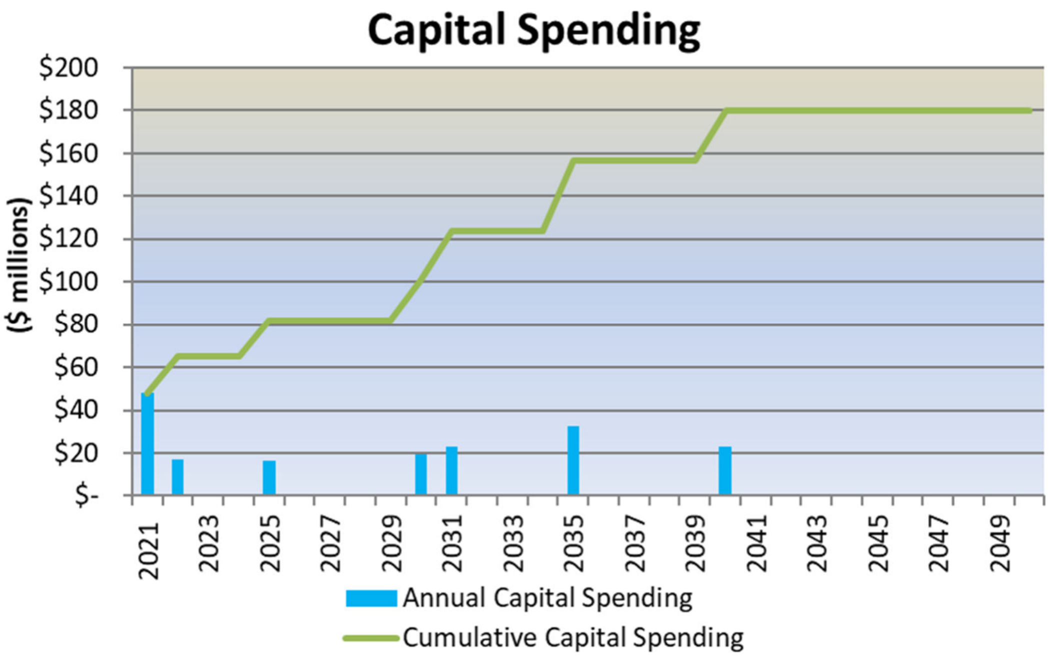


Figure 6-15 Capital Spending – Best Implementable per Technical, Geographical and Reasonable Factors

6.3.2.3 Annual Operating Cash Flow

Figure 6-16, Annual Operating Cash Flow – Best Implementable per Technical, Geographical and Reasonable Factors, presents a comparison of potential revenues generated from energy produced and the cost associated with implementing the portfolio of improvements. The revenues generated from energy produced represent the potential revenues that PREPA can generate due to the incremental increase in energy output. When compared to the cost to operate, existing O&M, incremental O&M, debt service, cash finance capital projects, and renewal and replacement, the revenue potential exceeds the cost to operate, which may provide opportunities for PRPEA to achieve cost savings with the implementation of the next increment of energy.

The operating balance over the 30-year study period is about $53.4. million for the portfolio discussed herein. In 2023, once construction is completed, the operating balance realized is estimated to be $56.5 million, and this total grows to about $76.3 million by 2050. Figure 6-16 shows that the space below the purple revenue line and above the bar graphs over the study period represents the cost savings that produce a positive NPV of about $687.5 million.

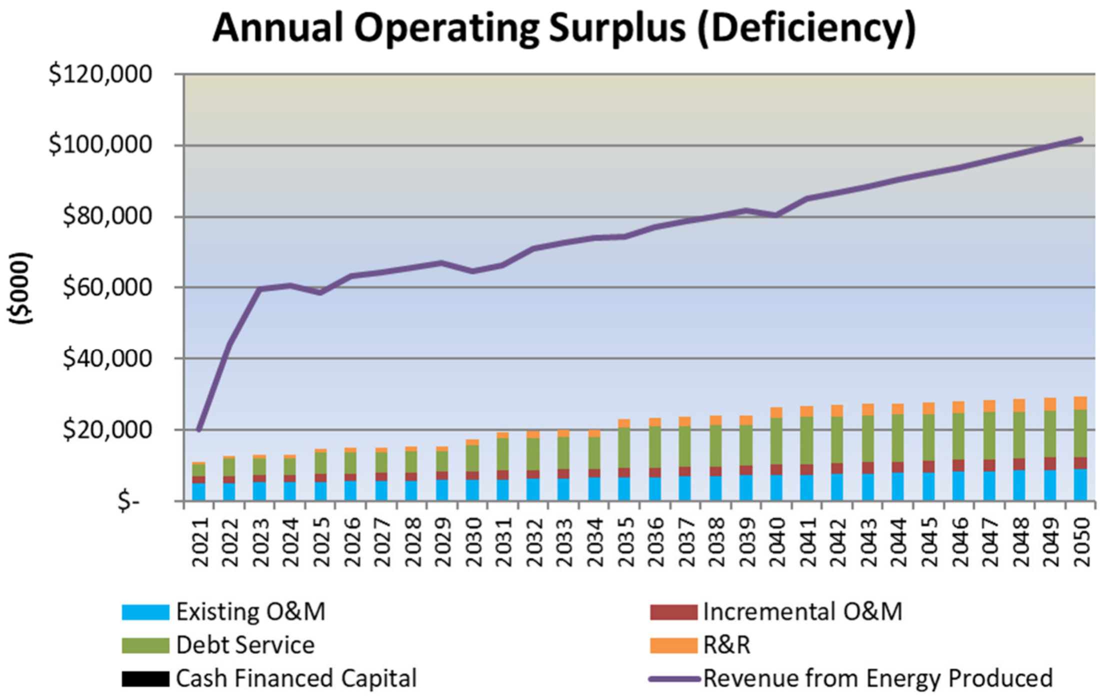


Figure 6-16 Annual Operating Cash Flow – Best Implementable per Technical, Geographical and Reasonable Factors

6.4 ECONOMIC FEASIBILITY ANALYSIS FINDINGS

As demonstrated in the previous section, the two portfolios analyzed 1. Highest NPV Improvement per Hydroelectric System; 2. Best Implementable per Technical, Geographical and Reasonable Factors, both produce significant positive NPVs, which indicates the financial feasibility of the next increment of Hydroelectric power by implementing the proposed portfolios of improvements. The general characteristics of each portfolio are similar, but provides specific perspectives for PREPA to consider upon implementation.

Portfolio 1, Highest NPV Improvement per Hydroelectric Facility, has a slightly higher NPV of the two portfolios. However, it is the only portfolio that does not rehabilitate all the Hydroelectric Facilities studied to good working conditions when it does not fully restore Toro Negro 2 and only implements the dredging option for Yauco 1 and Yauco 2. Current Hydroelectric Facilities that are inactive have been considered in evaluating this portfolio even though the improvements associated with these facilities, in some cases, produce a lower or negative NPV over the 30-year study period causing the overall portfolio NPV to be lower. This portfolio produces a cumulative NPV of about $695.8 million, with a lower capital implementation cost of $163.3 million.

Portfolio 2, Best Implementable per Technical, Geographical and Reasonable Factors, considers all the Hydroelectric Facilities that produce regardless of a positive NPV; and considers the logistical and operational difficulties of operating systems with water intakes deep in the Puerto Rico rainforest. This portfolio is financially feasible for PREPA and produces an NPV result of $687.5 million, indicating a very high potential generation cost savings for PREPA and its customers. The capital implementation cost is $166.3 million. In addition, certain Hydroelectric

Facilities such as Toro Negro 2, Yauco 1, and Yauco 2 will be upgraded and provide a positive impact on the O&M of each of the systems.

Figure 6-17 below provides an illustrative comparison of the two portfolios discussed herein.

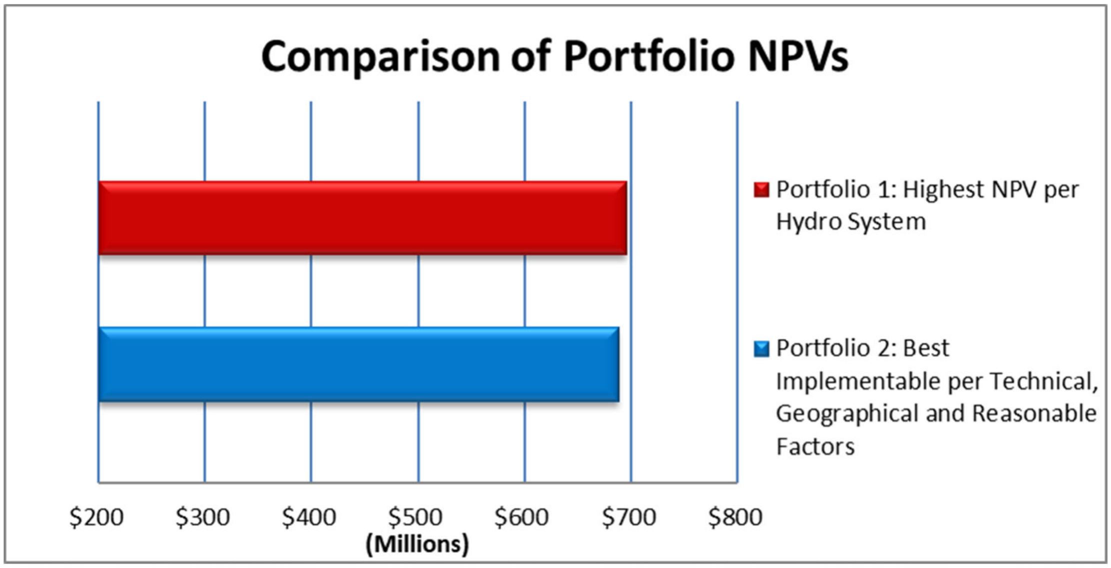


Figure 6-17 Comparison of Portfolio NPVs

Both Portfolios provide NPVs with significant value in the study period, with a difference of just over $15 million over 30 years. Portfolio 1 produces an NPV result of $695.8 million, while Portfolio 2 produces an NPV of $687.5 million. Average annual energy output for both is approximately 250,000 MWh at full implementation. The Portfolio 1 capital implementation supposes a cost of $163.3 million, while the Portfolio 2 requires an investment of $166.7 million. As such, assessing the economic impact of implementing the improvements associated with the two portfolios presented above should consider the financial feasibility and the most implementable portfolio that allows PREPA to reduce operating costs.

Based on the economic feasibility analyses performed herein, PREPA should consider implementing Portfolio 2 because it allows for the feasible investment, implementation, rehabilitation, operations, and preservation of valuable Hydroelectric Facilities that are an integral part of the island's infrastructure.

6.5 UNIT COST ANALYSIS AFTER IMPLEMENTATION OF RECOMMENDED IMPROVEMENTS

The analyses presented herein summarize the unit cost of energy produced related to the improvements presented in Portfolio 2. Determining the feasibility of the portfolio of improvements analyzed, and more specifically Portfolio 2, can be accomplished by understanding the relationship between PREPA's current unit cost of energy and the unit cost of energy produced associated with each portfolio before and after the implementation of the proposed improvements.

6.5.1 Unit Cost of Energy

Figure 6-18, Unit Cost of Energy, shows a projection of the unit cost of energy for PREPA for one kWh of energy over the study period. In addition, the approximate unit cost to produce one Hydroelectric kWh after the improvements are implemented at the Hydroelectric Facilities. For the analysis detailed herein, PREPA's unit cost of energy over the forecast period is utilized as the value for each unit of energy produced from the Hydroelectric Facilities after implementing the improvements.

In 2021, it is forecasted that PREPA will produce its energy from all resources at an average cost of \$0.181 per kWh and the associated unit revenues of \$0.226 per kWh. At the end of the study period, PREPA's forecasted unit cost of energy from PREPA will grow to about \$0.330 per kWh utilizing an annual inflation estimate of 2.0%.

For the analysis performed herein, it is forecasted that PREPA's unit cost to produce energy from the existing Hydroelectric Facilities is about \$0.067 per kWh in 2021, and this unit cost will grow to \$0.119 per kWh by 2050. On the other hand, the unit cost of energy produced by the Hydroelectric Facilities will be lowered in 2021 after implementing the improvements related to Portfolio 2. In 2021, the unit cost of Hydroelectric energy produced after the improvements is \$0.059 per kWh, and this unit cost will grow to \$0.105 per kWh by the end of 2050.

Figure 6-18 provides a summary of the unit cost of energy over the study period.

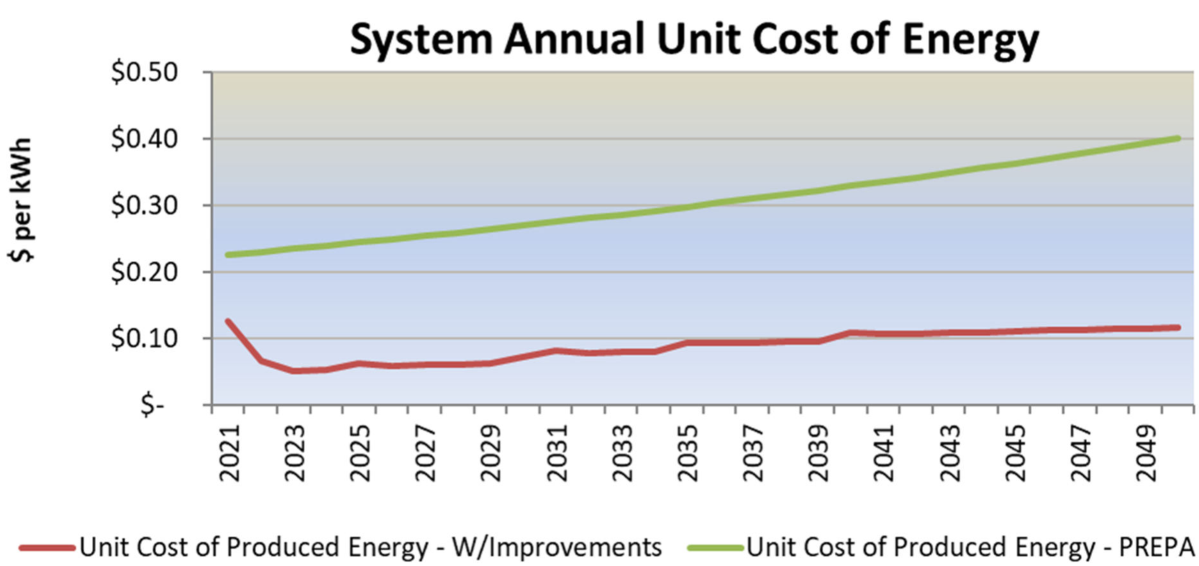


Figure 6-18 Unit Cost of Energy

As illustrated in Figure 6-18, the implementation of the improvements associated with Portfolio 2 provides a unit cost of energy savings over the forecast period over the overall aggregate cost of energy production for PREPA. The Portfolio 2 positive NPV of about $687.5 million is achieved upon implementing the proposed improvements. Over the study period, definitive savings are evident as the unit cost of energy produced after the improvements is compared to PREPA's existing energy cost produced from all energy resources on the island. As such, the potential unit cost of energy savings over the study period supports the financial feasibility of Portfolio 2.

7 Recommended Hydroelectric Facilities' Improvements

Black & Veatch proposes the implementation of Portfolio 2, Best Implementable per Technical, Geographical and Reasonable Factors, given the financial feasibility and potential benefits associated with this portfolio of improvements.

Black & Veatch recognizes that while some of the proposed improvements generate a higher NPV than this portfolio, the implicit benefits of those improvements evaluated may not be the most reasonable for PREPA.